The
Lines
Company
Limited

ASSET MANAGEMENT PLAN

2012

Copies of this plan are available at www.thelinescompany.co.nz

Cover photograph:

TLC Contracting staff performing night work on the Turangi 33 kV feeder

SCHEDULE 14

FORM 2 – CERTIFICATE OF ASSET MANAGEMENT PLANS

Pursuant to Requirement 11(2)

We, Angus Malcolm DON and John Carleton LINDSAY, directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge, the attached asset management plan of The Lines Company prepared for the purposes of requirement 7 (1) of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008 complies with those Requirements.

Date	Date
Angus Malcolm DON **Chairman**	John Carleton LINDSAY **Director**

Contents

Glossary

ABS..... Air Break Switch
AC..... Alternating Current
ACSR..... Aluminium Conductor Steel Reinforced
Al..... Aluminium
AMG..... Asset Management Group
AMP ..... Asset Management Plan
CAPEX ..... Capital Expenditure
CPI ..... Consumer Price Index
Cu..... Copper
DC ..... Direct Current
DG ..... Distributed Generation
DGA..... Dissolved Gas Analysis
DOC..... Department of Conservation
DoL..... Department of Labour
Dy..... Delta-star
EGCC ..... Electricity and Gas Complaints Commission
ETAP..... Electrical power system analysis software
GIS..... Geographical Information System
GXP ..... Grid Exit Point
HSE..... Health and Safety in Employment (formerly OSH)
ICP..... Installation Control Point
KCE..... King Country Energy
LDC..... Leased Direct Circuit
LV ..... Low Voltage (400 Volts)
MDI ..... Maximum Demand Indicator
MD ..... Maximum Demand
MED ..... Ministry of Economic Development
MRP ..... Mighty River Power
ODV..... Optimised Deprival Value
PILC ..... Paper Insulated Lead Cable
POS ..... Point of Supply
RAB ..... Regulatory Asset Base
RAL..... Ruapehu Alpine Lifts Ltd
RCPD ..... Regional Co-Incidental Peak Demand
RTE..... A type of internal rotary transformer switch
RTU ..... Remote Terminal Unit
SAIDI ..... System Average Interruption Duration Index
SAIFI ..... System Average Interruption Frequency Index
SCADA..... Supervisory Control and Data Acquisition
SMS..... Safety Management System
SWER ..... Single Wire Earth Return
TDMA..... Time Division Multiple Access
TLC ..... The Lines Company Ltd
UHF ..... Ultra High Frequency
VHF ..... Very High Frequency
WACC..... Weighted Average Cost of Capital
XLPE ..... Cross-Linked Polyethylene Cable
Yd..... Star-delta
YY ..... Star-star

STANDARD UNITS AND PREFIXES

m	milli	(x 10^{-3})
k	kilo	(x 10^{3})
M	mega	(x 10^{6})
G	giga	(x 10^{9})
A	amperes (AMP)	Current
g	grams	Weight
Hz	hertz	Frequency
m	metres	Distance
m/s	metres per second	Speed
N	newtons	Force
V	volt	Voltage
VA	volt-amperes	Apparent power
W	watts	Power
Wh	watt-hours	Energy

VARIANCE CALCULATIONS

For the purposes of the AMP, variance has been calculated as follows:

$$\text{Variance} = \frac{(\text{Actual} - \text{Target})}{\text{Target}} \qquad \text{which may also be written as} \quad \left(\frac{\text{Actual}}{\text{Target}}\right) - 1$$

When actual results are better than expected, the variance is deemed favorable and preceded with an (F).

When actual results are worse than expected, the variance is deemed unfavorable and preceded by (U).

Section 1

1. Executive Summary

The principal objective of the Asset Management Plan (AMP) is to meet the requirements of stakeholders as reflected in the Statement of Corporate Intent, the agreement between The Lines Company (TLC) and its owners. This agreement obliges TLC to continue to invest in its network to undertake a sustainable renewal programme to minimise/eliminate hazards and meet reliability targets.

The network covers the area shown in the illustration below.

FIGURE 1.1: AREA OF NORTH ISLAND OF NZ WHERE TLC ASSETS ARE LOCATED

The TLC network has many contrasts and includes:

- 60 single wire earth return systems (SWER).
- A direct connection to two major generators upstream of the Transpower grid exit. (Atiamuri, Whakamaru)
- A generator directly connected energy park network supplying energy intensive industries.
- Distributed generation connections.
- A number of large industrial connections.
- A slow growing population base.
- A rugged rural environment.
- High number of necessary zone substations.

- Long lengths of 33 kV lines in mainly rugged and remote areas.
- Long lengths of privately owned 11 kV lines connected to the network.
- Approximately 30% of TLC assets are used to supply remote customers who provide approximately 12% of the revenue.

The assets have a regulatory value of $184 million. (Values using March 2011 Commerce Commission 53ZD Notice methodology.)

TLC's assets are old by industry standards with the highest proportion of any line company (39%) within 10 years of total life[1]. The average age of the fixed assets is 36 years, the second highest when compared to other network companies.

The two original networks that now make up the TLC network did not experience the large asset renewal programme that most networks in New Zealand experienced in the 1970's. The network has experienced low growth over recent years and there has consequently been no reason to invest in large amounts of new assets. There has been no renewal 'by product' effects from the extensive growth many networks have experienced.

The forward expenditure predictions in the previous AMP and this AMP reconcile approximately to the age based Commerce Commission Farrier Swier consulting report as part of the work leading up to the 2010 regulatory reset. The differences are associated with hazard elimination/minimisation and localised issues.

There are no large urban centres in the area covered by TLC. This has the following implications:

» Firstly, there is limited ability to cross-subsidise rural supplies. Rural customers must therefore be exposed to a price that is closer to the cost of supplying them than is traditional in other parts of New Zealand. That price, at times, is at the limit of what the customer is willing to pay. Thus, there is a limited ability to cover extra rural investment from existing customers. Renewals will increase the values of these assets and thus revenue requirements.

As a consequence they have to be managed in a way that fulfils hazard control requirements, produces the optimum service level and minimises the value increase. This is reflected in our segment-by-segment approach to asset development, renewal, and maintenance, and our commitment to greater information flows to our rural customers so that they can better understand the cost of supply and more adequately decide on the trade-off among cost, service and hazard control. This approach and improved data will be vital for putting options to customers and making decisions given the government's intent to continue with the obligation to supply beyond 2013 and the need for this to be funded from existing customers.

Imposing the renewal costs of all TLC's uneconomic lines, most of which were originally funded by grants from the Rural Electricity Reticulation Committee (RERC), on TLC's customers as a sole funding source means that urban customers will face line charges above the cost of supply. The deprived urban areas cannot sustain substantial price increases to fund this work.

Many aspects of hazard control are non-negotiable in terms of legislation and from a practical sense preventing lines from falling down are also part of the quality consideration. Balancing these issues and the obligation to maintain supply to remote rural areas whilst maintaining reliability, renewing assets and providing acceptable dividends to stakeholders are part of the challenge facing TLC.

During the 2011/12 AMP review, work was prioritised to minimise this impact; however, it does mean that work on minimising hazards was spread further into the future. The 2012/13 and 2013/14 reviews are continuing with this approach.

[1] PWC Electricity Line Business 2011information Disclosure Compendium

» Secondly, it is important that the income from the towns is not simply used to subsidise rural supply, leading to the towns themselves receiving a substandard supply. The strongest domestic growth in the region is from holiday homes. These homeowners on the whole are willing to pay a reasonable line charge, but do expect a service level that is close to what they receive in their permanent residences in return. There has been a lack of investment in some of these towns in the past. Investment in the infrastructure for these towns, especially Ohakune and Turangi, has been significant in the past nine years, and continues to feature in this Plan.

» Thirdly, urban areas normally have much fewer outages, as the income from such areas justifies investment in back feeds and other supply enhancing assets. If most network customers are located in an urban area then the low urban number producing a low average will mask the high rural outages. The lack of this masking effect means that TLC's outage figures will always be close to the industry extreme.

The Electricity Industry uses two core standard assessments of service level; System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In 2003 TLC carried out a customer survey that provided sufficient data to allow the establishment of target performance levels for these two assessments. In 2009 the Commerce Commission released Decision 685 which set independent normalised reliability limits for both SAIDI and SAIFI. In 2010 the Board of TLC determined that the SAIFI performance level target should be increased. This determination was in line with best practice asset management that required the initiation of a significant network renewal programme.

Figure 1.2 shows the Customer and Compliance reliability targets

CUSTOMER AND COMPLIANCE RELIABILITY TARGETS		
Target	**SAIDI**	**SAIFI**
TLC Customer Target	300.00	4.86
Normalised Compliance Target	307.69	4.15

FIGURE 1.2: RELIABILITY TARGETS

The Commerce Commission reliability limits are comparable with TLC's SAIDI and SAIFI target performance levels. AMP forecasting expects to revise these target performance levels as part of the on going customer consultation. The renewal programmes outlined in this document aim to maintain the company's SAIDI and SAIFI performance targets at levels that meet stakeholder expectations. As already noted in the decision to increase SAIFI performance targets, these stakeholder expectations may be contradictory.

The Asset database (BASIX) provides the raw data for both the compliance reliability limits and the actual/target performance levels of SAIDI and SAIFI.

The actual performance data for SAIDI and SAIFI have different influences. Measures to reduce SAIDI may act to increase SAIFI. An example of this is the increased use of automatic network switches that reduce the duration of an unplanned outage, such as bird strike, but may increase the frequency of unplanned outages. Unfortunately unplanned weather and other natural events may cause extraordinary network outages. This would significantly affect the actual data provided for SAIDI and SAIFI and depending on the severity may cause TLC to miss both performance targets and compliance limits.

TLC is considering the option of a Customised Price Path application (CPP). This option has been provided by the Commerce Commission and recognises the unique profile of different networks. As noted TLC has a large aged rural network. Planned network renewals may mean the current compliance limits and performance targets are breached. Planned customer consultation may find an acceptable level of performance targets that result from a compromise between price and service quality.

Figure 1.3A and 1.3B show the historical data for both SAIDI and SAIFI along with TLCs performance target. Transpower related outages are not included in these illustrations.

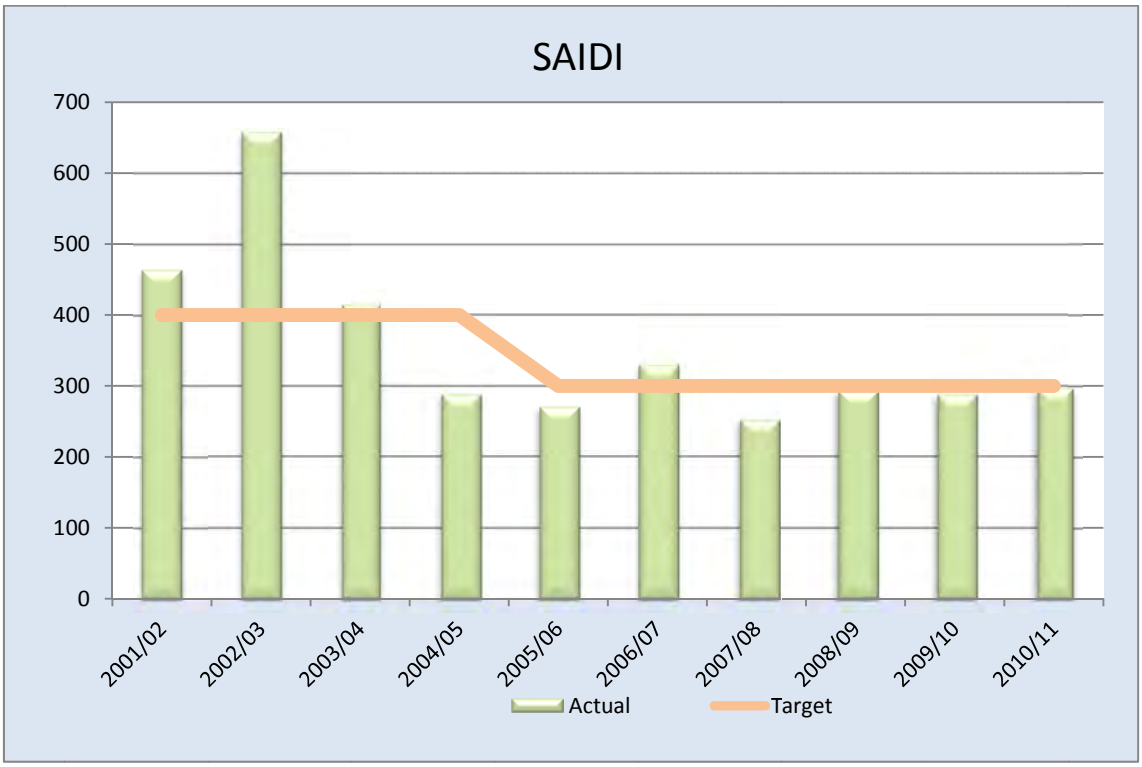


FIGURE 1.3A: 2002-2011 TOTAL SAIDI (EXCLUDING TRANSPOWER)

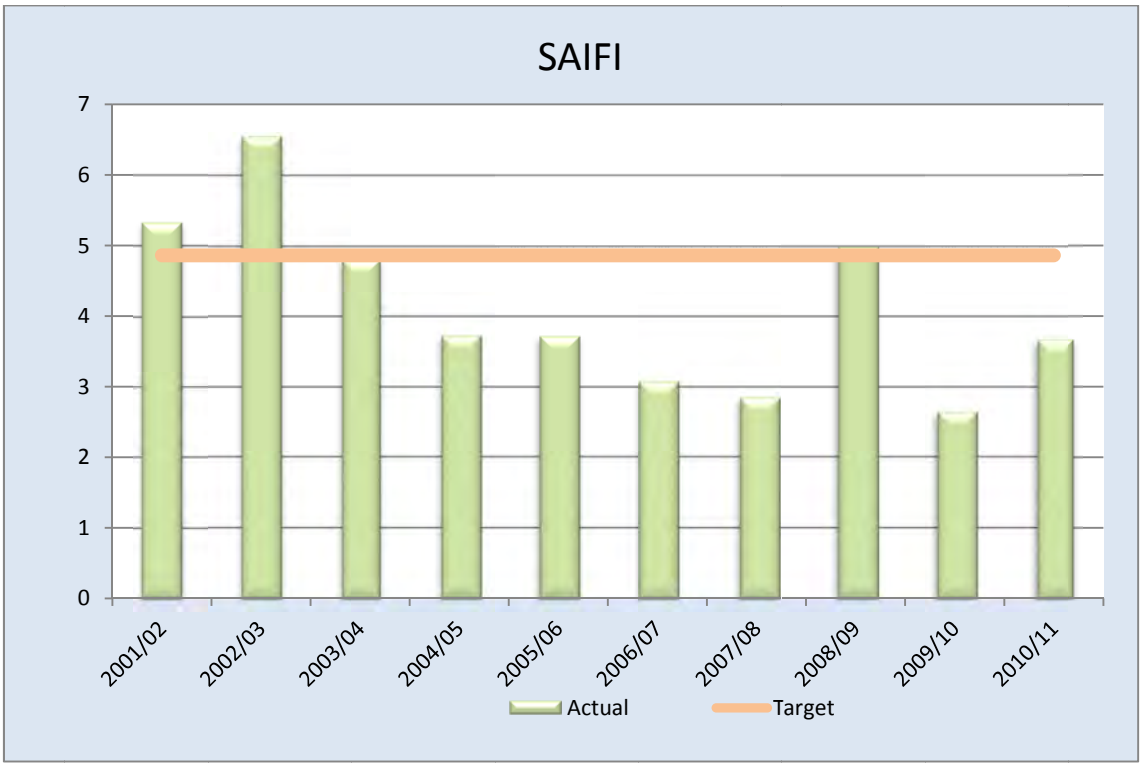


FIGURE 1.3B: 2002-2011 TOTAL SAIFI (EXCLUDING TRANSPOWER)

The improvement is evidence to show that TLC's asset management programmes are working. The reality is that it takes time to cement in many of these strategies across a large infrastructure asset such as an electricity network.

Environmental factors including lahars, storms, earthquakes, floods and snow all present risks to the network. There are large sections of the network that were constructed after the Second World War years by farmers to supply remote areas. These installations were fit for purpose at that time and were constructed at low cost. They inherently have a lesser ability to withstand extreme weather events than more expensively constructed and resilient networks.

Vegetation and other maintenance/renewal programmes are essential for getting these installations to perform to present day expectations with an acceptable level of hazard risk. Feedback from customers suggests that most are happy with the performance of the network over the past few years, and instead are looking for other benefits, such as ways to control costs. Some customers are also asking for under-grounding in holiday areas. Allowances in this Plan include replacing many of the aged, high risk, low voltage systems in holiday areas with aerial bundled conductor reticulation. Additional funding to go to the next stage of undergrounding would have to come from an external source.

The network area also encompasses significant energy generation resources. There are currently over 25 distributed generation machines connected. As the Plan notes, applications for new generation connections are increasing, and many of our projected constraints are caused by the limited ability of our network to receive the projected injection.

Much of the generation is at remote sites and is utilising TLC's extensive 33 kV network. In some situations, it is possible that high load customers will leave the areas, meaning that the cost of renewing and supporting distant sections of the 33 kV network will possibly need to be supported by these generators. This will lead, in some cases, to uncertainty in pricing levels.

Most of the generation is renewable with little or no storage. Run of the river hydro schemes produce the highest outputs after wet periods, which predominantly occur in the winter months. TLC's industrial load peaks tend to occur in the summer months when demands for meat, limestone, and forest processing are at their highest. This means that the distributed generation does not often reduce network expenditures. Network assets have to be put in place to handle load off take without generation and, vice versa, maximum injection during light load times. The charging regime to generators has to reflect the fair value of asset installation, renewal, and maintenance costs based on the asset utilisation by this activity. This tends to be determined on a generator-by-generator basis.

Distributed generation adds technical complexity to operating, maintaining and developing the network. For example, it substantially reduces grid exit power factors. Generation can have benefits and TLC is encouraging investors to operate plants in a way that both they, and TLC, can maximise these.

With any aged assets, issues of hazards and their attendant risks arise. It is our first priority to eliminate or mitigate any hazard that comes to our notice that has a high probability of causing serious harm to either employees or members of the public. Recent AMPs and works programmes have addressed high-risk hazard issues. New Zealand Standard 7901:2008 provides for further documented proof that all practicable steps are taken to prevent *"serious harm to any member of the public or significant damage to property from electricity generation, transmission or distribution network assets, and the operation of these assets*." The Plan includes allowances for the completion of the high-risk improvements, and all of the medium and known lower risk issues will be addressed through the planning period.

Engineering resources continue to be a constraint, but a combination of additional staff, and existing staff up-skilling, is taking place in the engineering and asset management area to address this. Any work, whether it is maintenance, renewal or development, needs to be adequately designed if it is to be cost effective. Unfortunately, there are limited resources within New Zealand that have an understanding of the problems of remote rural networks, and experience can only come over time.

This problem is being further amplified by the increasing requests for information and compliance from various government and other agencies. These requirements now consume a significant amount of engineering time that would give greater benefit to customers if it was focused on developing innovative solutions. In an effort to minimise the impacts of these requests, TLC continues to invest in new data systems that are automating much of this reporting in an effort to control compliance costs. Recent initiatives have included automating much of the Safety Management System (SMS) and forward renewal job system.

In order to gain the full benefit from our engineering resource we ensure that they are focused on engineering matters and that non-engineering staff are used for other duties wherever possible. The projected direct maintenance expenditure for the planning period is predicted to track as illustrated in Figure 1.4. An inflation rate of 3% has generally been used.

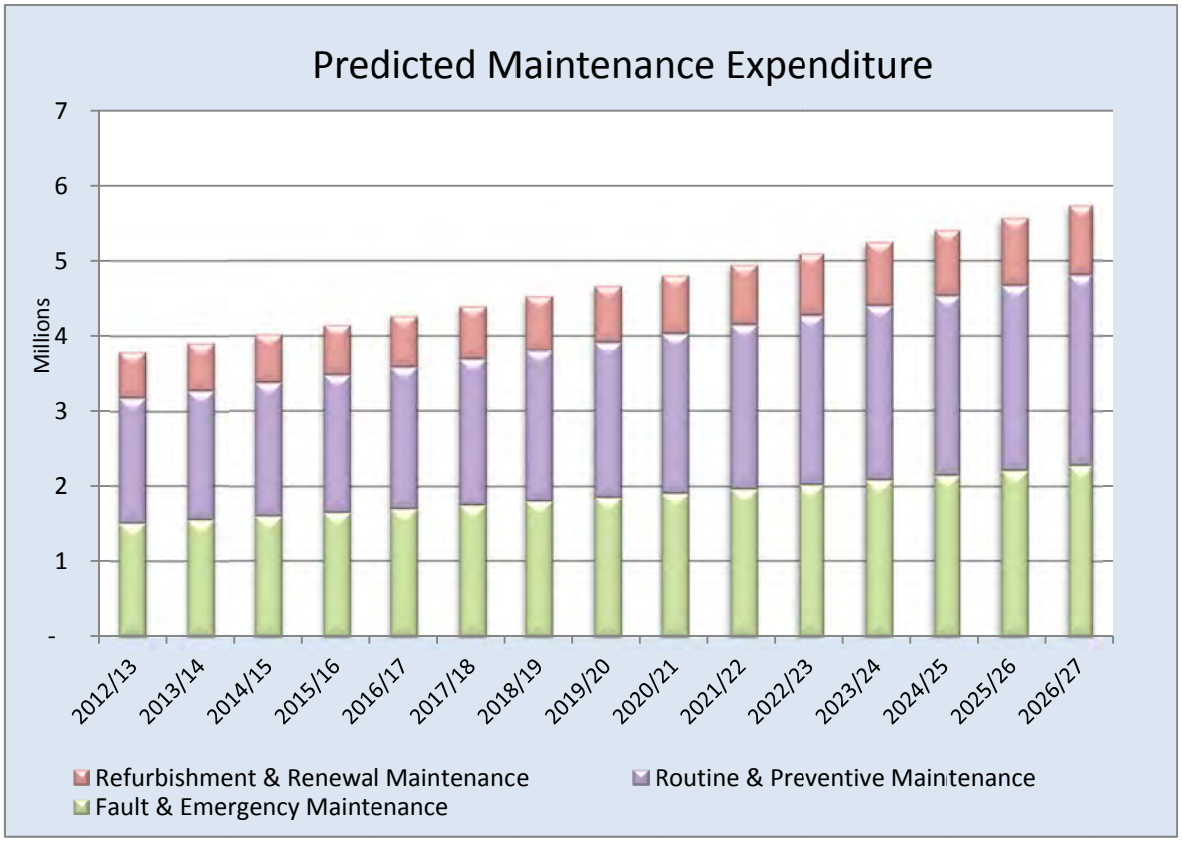


FIGURE 1.4: PREDICTED DIRECT MAINTENANCE EXPENDITURE (AS DEFINED BY 2008 COMMERCE COMMISSION DISCLOSURE REQUIREMENTS).

The major cost included in maintenance expenditure is vegetation control. Since 2007/08, initial cutwork has been slowed and focus has been placed on maintaining the gains that have been made since the poor reliability years around 2002/03. This has involved the issue of many second cut and trim notices and completing three yearly inspections of the network. Customers are generally co-operating in either trimming trees, or they allow TLC to do total removals.

Figure 1.5 illustrates the predicted forward capital expenditure for the planning period in 2010/11 dollars plus forward inflation of 3%.

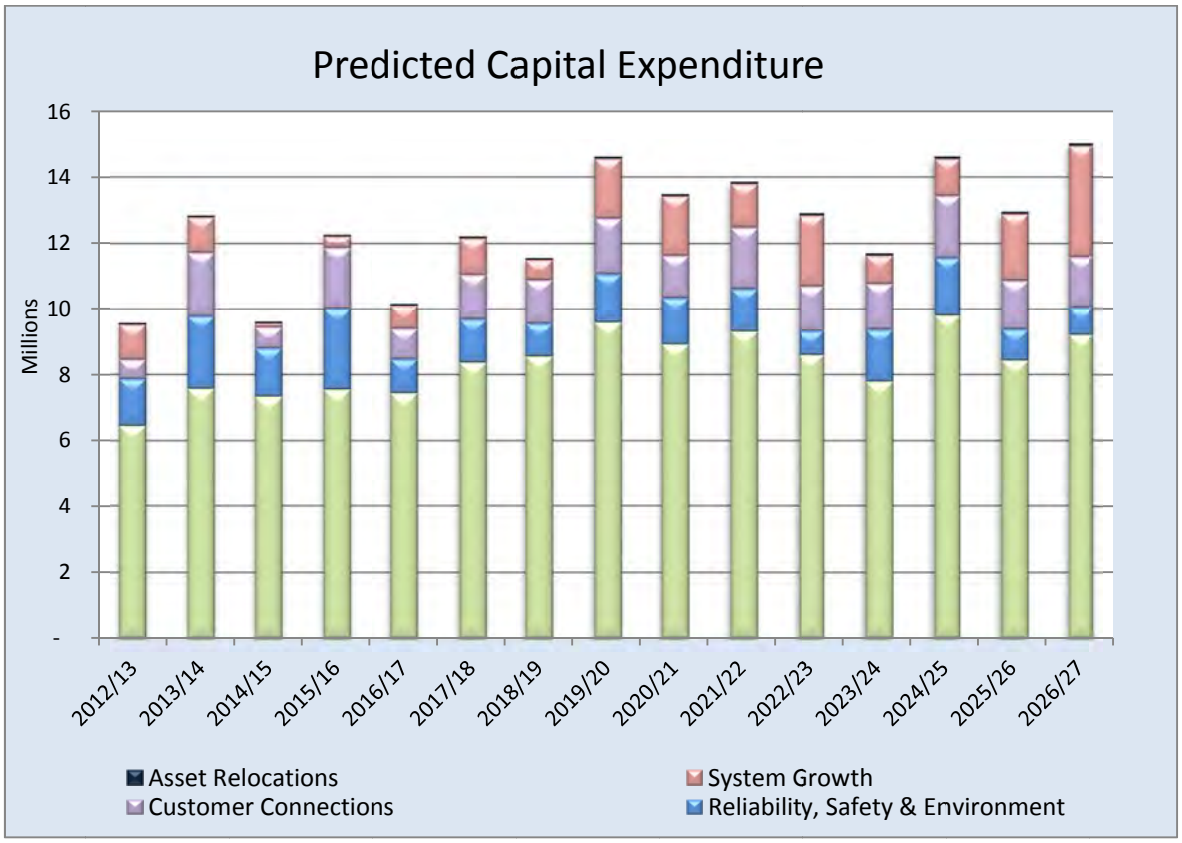


FIGURE 1.5: PREDICTED CAPITAL EXPENDITURE
(AS DEFINED BY 2008 COMMERCE COMMISSION DISCLOSURE REQUIREMENTS).

The CAPEX predictions are the output of a complete review of network needs. These predictions are based on renewals to meet the hazard elimination/minimisation, reliability, and quality expectations of stakeholders and allow the levels of growth that are expected. The estimates are the sum of actual projects and contingencies have been included only for unknown reasons such as emergent repairs and renewals that are necessary to keep the system operating.

This level of capital expenditure will drive up prices and given the work is necessary due to the age and condition of assets the challenge for TLC is to do this work at costs below estimates. Any such savings will reduce the level of potential revenue increase needs.

The risks of price shocks to customers will also come from increases in Transpower charges, an escalation of data and compliance requirements by government agencies, earlier decisions to minimise renewals, the imposition on TLC's customers to fund, unaided, the costs of renewing TLC's uneconomic lines that were originally constructed using RERC funds and requests by customers to improve reliability to less than the targets listed in table 1.2.

In July 2011 the Commerce Commission issued a draft decision to reset regulatory controls for the electricity distribution businesses from 2012 to 2015 in which TLC is included.

Section 2.24 of the paper[2] shows that the present value of revenue that TLC would be projected to earn relative to the amount required to earn a normal return over the full five years of the regulatory period is negative $17 million. Section 2.16 of the paper (i) shows that indicative adjustment to maximum allowable net revenue in 2012/13 is 14% and the annual percentage rate of change – 1%; 2013/14, 2014/15 is CPI plus 5%. At the time of writing, no decisions have been taken on how these regulatory approvals are to be applied.

Over the last years, TLC has introduced direct billing and, in response to customers' requests for flat annual charges, introduced demand based charging for all customers. Customer bills are now made up of capacity, demand and dedicated asset charges. These are also area specific to allow customers to make choices on what they want. These charges encourage demand reductions including the control of peaks, alternative generation during peaks, maximising dedicated asset utilisation, minimising installation capacity requirements and, for larger installations, responses to reactive power signals. The way these concepts are applied is currently under review by stakeholders.

In an effort to minimise costs, given the need for renewal exists, TLC is looking to new innovative solutions. The foundations, which include demand based billing, improved network, customer and financial data and detailed network analysis/automation tools, are in place. Intellectual learning is underway, and many ways through which the network can be tuned to improve efficiency for minimal cost have been identified, and are being systematically applied. For example, better ways of tuning distributed generation to run in conjunction with TLC voltage control equipment have recently been identified and TLC is currently working with one generation owner to implement improved schemes. TLC demand billing and pricing systems are also undergoing continual development to increase the incentives for customers to manage demand for both active and reactive power. These initiatives are integrated and form the basis for a "smarter" network.

A likely outcome of these initiatives will be deployment of advanced meters that include the load control function over the entire network during the coming years.

Network growth is driven either by subdivisions for holiday homes, lifestyle blocks, commercial development, and by the plans of our major customers. Apart from the western coastal area and the Western Bays of Lake Taupo, the subdivision growth is generally close to the sub transmission network. The growth itself is cyclic and uncertain. This organisation cannot afford to carry assets that are substantially under utilised. TLC therefore has a low organisational appetite for planning risk, investing instead in the resources to maintain a close contact with the customers, and other drivers of growth, so that we can ensure that network development occurs only if, and when, it is required to produce revenue.

Growth is funded from borrowing, as the revenue stream from the growth should meet the borrowing costs. This approach means that customer growth is not constrained by funds.

A matter of concern to TLC is that grid connection transformers which provide supply to TLC at 33 kV or 11 kV are, at two connection points, now loaded at system peaks at levels close to their ratings (with the network in certain configurations). When system peaks growth forces increases in the capacity to be provided at these points, increases in connection and inter connection charges will occur. These should be met by the consumers supplied from those points. The need to postpone such cost increases was a major driver in TLC's decision to move to capacity and demand charges for its pricing option. However, better control on demands will also postpone expenditure on necessary capacity increases in TLC's own network.

As a side benefit, the moving of consumer loads to off peak periods as demand pricing encourages consumers to lower their load during these times, will have the effect of raising the network's overall load factor, and minimising the losses in the network, and increasing the efficiency of the energy carriage function.

2 Commerce Commission, *2010-15 Default Price Quality Path for Electricity Distribution, Draft Decision Paper*, July 2011

Much has been said about alternative supply solutions; however, work completed by TLC and other independent bodies shows that these technologies are not advanced enough to meet the needs of busy farmers who are focused on maximising the efficiency of their enterprises.

The reality is that these supplies can be suitable for short term operations such as woolsheds but they do not provide the convenience most customers expect from a power supply. Most lifestyles require a supply reliably available on a 24 hours a day, seven days a week basis.

The costs, particularly of solar cells, have reduced over the last year or so; however, economic analysis shows that they are still a distance away from competing against present energy rates.

TLC is continually monitoring these technologies and is recommending them to customers when they are more economic and capable of producing similar lifestyle or enterprise outcomes.

TLC recognises that the government will not fund rural lines and, as a consequence, it must use some other approach to ensure customers can afford to pay for their electricity supply.

A major element of a different approach is demand side management through demand billing. TLC has evidence of two effects from recent data of its demand side management initiatives.

- Firstly, retailers have not increased energy charges in the same proportion as the rest of New Zealand. De-coupling appears to have placed greater pressure on retailers to avoid price increases and “hidden” repackaging margins.
- Secondly, demand growth data is indicating that customers are responding and shifting load. Initial analysis is showing that the impact this could have on delaying development expenditure is such that it will allow TLC to complete its renewal programmes.

The effect of steadier cost energy rates and strong incentives in line charges to reduce demand gives customers options to ensure total electricity accounts are competitive with other places in New Zealand, (even densely populated urban areas). TLC’s challenge is to deliver these innovative approaches in such a way that customers recognise their choices and options.

Now that the reliability has been stabilised, the next challenge is to complete the renewal programmes at lower costs than estimated. The achievement of this will be of pricing benefit to customers.

Section 2

2. Background and Objectives

2.1 The Purpose of the Plan

The primary purpose of this document is to communicate the asset management policies, processes and outcomes adopted by TLC to all interested stakeholders. The Asset and Engineering Department prepare the plan annually after reviewing previous years' Plans and discussing the information that stakeholders wish to have included. The Plan therefore incorporates information that is prepared for other planning purposes, or is the result of the asset management process adopted by the company.

The Plan is drafted to comply with the Electricity Information Disclosure Requirements 2004 as amended by the 31 October 2008 Amended Requirements. The Plan is aligned to and is part of TLC's asset management policy and forms a significant part of the asset management strategy. It is also aligned to and forms part of TLC's Safety Management System (SMS).

If the electricity information disclosure requirements did not exist it is likely that the asset management planning process would be part of TLC's annual plan and the Plan would become more aligned to the international PAS 55 standard.

The Plan has been continually developing since the initial version was written in 2000 and over the last few years has become one of the key internal planning documents. The importance and significance of the document has been increasingly recognised by stakeholders, regulators and staff, and feedback is welcomed. The Plan has a purpose to inform stakeholders of the implications of growth, renewal, hazard elimination, maintenance, vegetation, and other expenditure streams on service levels and risks, such as levels of hazards, for both the short term and longer term. The document also gives customers an understanding of the links between asset costs and pricing structures, including the need for future adjustments to fund asset renewals. Figure 2.1 illustrates the documents and papers that have a relationship with the writing of the AMP.

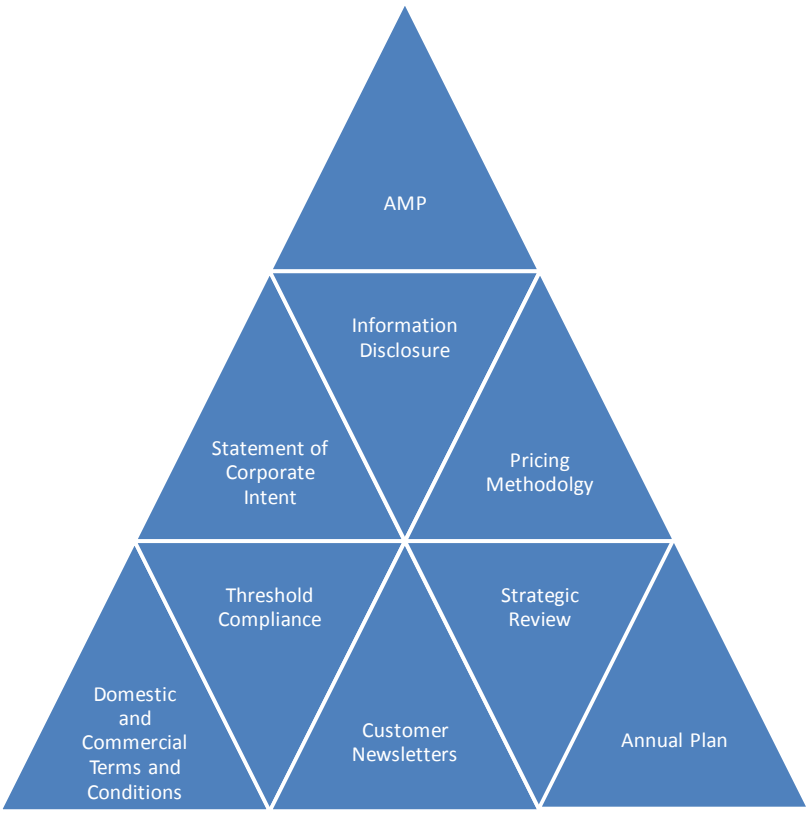


FIGURE 2.1: RELATIONSHIP PYRAMID OF AMP

The area supplied by the TLC network includes large areas of Maori owned and other long term tenure land. TLC assets are located on this land and a purpose of this Plan is to document its intentions for these assets for the short, medium and longer terms.

In addition to disclosing network information, the Plan has the objective of forming the documented base for all engineering/asset planning implementation processes and activities. The Plan discloses the asset information and processes used to manage the assets to all stakeholders.

The Plan also has a purpose to provide the framework that enables asset management strategy objectives and detailed plans to be produced and implemented. These include the principles to be applied, such as the organisation's approach to hazard control and sustainable development. The Plan is consistent with TLC's vision/mission statements.

2.2 Description of the Interaction between these Objectives and Other Corporate Goals

2.2.1 High Level Corporate Mission or Vision

The high-level corporate mission or vision for the network business is to be recognised as the best supplier of electrical capacity to remote rural customers. This includes both load and generation customers.

TLC believes that by adopting this mission it can develop a long-term sustainable business for the benefit of its owners, while giving its customers an energy supply that is as reliable, secure, sustainable and efficient as is practicable in the circumstances.

The company recognises that one of its main missions is to deliver a strong sustainable network to the greater King Country area, as covered by its two trust shareholders. In order to do this, it will continue its investment in network renewal and development. It will use innovative customer billing and engineering to encourage demand side management and other network tuning to maximise network utilisation and minimise, as far as practical, customers' combined network and energy costs.

TLC has identified that in order to meet this requirement it must excel in:

- Asset management including:
  - » Asset management strategies consistent with other organisational polices and strategies and the needs of stakeholders.
  - » Asset management strategies that take into account the lifecycle of assets, asset types and systems over which the organisation has control.
  - » A documented asset management plan across the lifecycle of its assets.
  - » Communicated plans to all of the relevant parties to a level of detail appropriate to the roles of the reviewers.
  - » Designated responsibilities for delivery of asset management actions.
  - » Appropriate arrangements are made available for the efficient and cost effective implementation of the plans.
  - » Plans and procedures for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities.
  - » A management team responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy objectives and plans.
  - » Provision of sufficient resources for asset management.
  - » Communication of the importance of meeting asset management requirements.
  - » Where activities are outsourced, ensuring that appropriate controls are in place to produce compliant delivery of its organisational strategies/plans, including asset management.
  - » Developing plans to secure the human resources required to undertake asset management activities.
  - » Identifying competency requirements and then plan, provide and record the training necessary to achieve the competencies.
  - » Ensuring that persons under the organisation's direct control undertaking asset management, have an appropriate level of competence in terms of education, training or experience.
  - » Ensuring pertinent asset management information is effectively communicated to and from employees, or other stakeholders including contracted service providers.
  - » Documentation to describe the main elements of the asset management system and the interaction between them.
  - » Determining what the asset management information systems should contain in order to support its asset management system.
  - » Maintain asset management information systems to ensure that the data held is of requisite quality and accuracy, and is consistent.
  - » Ensure its asset management information system is relevant to its needs.

  - Documented processes and/or procedures for the identification and assessment of asset and asset management related risk throughout the asset life cycle.
  - Ensure that the results of risk assessments provide input into the identification of adequate resources and training/competency needs.
  - Ensure the organisation has identified and provided access to its legal, regulatory, statutory and other asset management requirements and incorporated these into the asset management system.
  - Establish, implement and maintain processes for the implementation of its asset management plan and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities.
  - Ensure that processes and/or procedures for the implementation of the asset management plan and control 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.
  - Have in place indices to measure the performance and condition of assets.
  - Ensure the organisation has delegated responsibility and the authority for the handling, investigation and mitigation of asset related failures, incidents and emergency situations and non-conformance is clear, unambiguous and communicated.
  - Established procedures for the audit of its asset management systems.
  - Instigate appropriate corrective and/or preventative actions to eliminate or prevent the causes of identified poor performance and non-conformance.
  - Ensure continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole lifecycle.
  - Seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation.

- Pricing structures that promote energy efficiency, the reduction of network energy demand and better asset utilisation.
- Customer consultation and promotion of demand side management.
- Demand side control systems and advanced metering.
- The investigation and promotion of network alternatives.
- Asset renewal and hazard control programme management including SMS strategies compliant with NZS7901:2008.
- Network analysis/automation and the intellectual learning needed to develop advanced systems.
- Innovation in all aspects of the business.
- Completing works in a manner that minimises costs whilst meeting stakeholder quality expectations. This includes informing customers of the trade-offs associated with energised versus de-energised work.

2.2.2 The documented plans produced as outputs of the annual business planning process

The documented plans that are produced as a result of the annual business planning process include:

- Strategic Review
  This document outlines the business activities that TLC is involved in and contains high-level details on the business environment and the planned strategies for these areas of activity.
  This document is approved by Directors.
- Statement of Corporate Intent
  This document is prepared in parallel with the strategic review and contains more detail.
  This document is approved by Directors.
- Asset Management Plan (AMP)
  Key document covering the major investment owned by TLC.
  This document is approved by Directors.
- Annual Plan/Budget
  Operating document detailing activity budgets approved by Directors.
  This is prepared in parallel with the Asset Management Plan.
- Monthly Board Reports
  Reports to Directors updating them on progress against the plan and detailing other issues that they need to know and/or approve.
- Annual pricing reviews.

2.2.3How the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management

TLC's planning process commences at the ownership level with the strategic review of the businesses that TLC is in, the purpose of these businesses, and whether each business can return, on a sustainable basis, a margin above our cost of capital.

The Strategic Review includes a financial analysis on the position of the network business based on the expenditure requirements derived from the Asset Management Plan. This analysis sets the high-level revenue requirement. Another major contributor to the outcomes of this analysis and subsequent decisions is the Commerce Commission Default Price Path. The 'rules' as set by the pricing regulator have a bearing on TLC's strategic direction. The Strategic Review also summarises the high level corporate strategy and includes an update on the criteria for new business activities.

The Statement of Corporate Intent is prepared in parallel with the Strategic Review and contains more detail. It includes key performance objectives of the network business, which are based around the contents of the current Asset Management Plan. There are close ties between the three documents.

The asset management policies and strategies that flow into this plan are identified from the Strategic Review and Statement of Corporate Intent and the strategies put in place to achieve these through the management of the physical assets.

The principal driver for revenue is the condition of the assets and the need to have a sustainable network that meets customers' expectations, including acceptable hazard related risk levels whilst producing a 'WACC' (Weighted Average Cost of Capital) within the regulatory bounds.

The ability of customers to pay is recognised in all documents and is an important consideration in the annual pricing review. This process ensures that the asset management strategy is consistent with other organisational policies and needs, and aligns with the needs of other stakeholders. The Annual Plan/Budget is a more detailed, activity level document that also fits under the Strategic Review, Statement of Corporate Intent and AMP.

Much of the detail in the Annual Plan replicates the present to one year out sections of the AMP. Specific detail is included on individual projects such as design outlines and financial evaluations.

Once approved, monthly reports to Directors document the progress against planned work for financial and other performance indicators. Monthly reports also include six monthly and annual updates against the AMP and Annual/Budget plans.

Feedback into future documents comes via Directors' resolutions and minutes from monthly and other meetings. The next cycle of documents includes this feedback. Any variations to the plan are approved by Directors at monthly meetings during the year. The documents include feedback and consideration coming from stakeholders and the associated regulatory/government requirements.

All stages of this process recognise the 'doing' aspects of asset management including asset lifecycles, performance and costs to users.

2.3 The Period Covered by the Plan and the Date the Plan was Approved by the Board of Directors

This Plan covers the period 1st April 2012 through to 31st March 2027. The Board of Directors approved it on the 29th March 2012. The Plan is reviewed annually.

Due to the age of the network and historic practices, many of the assets within the TLC network fall short of present day hazard and risk expectations. The Directors have requested priority on hazard related asset renewals in order to eliminate or minimise known risks of harm to the public or employees.

It needs to be acknowledged that the TLC network covers a large area with low population densities. There are no fast growing urban areas. The growth of the network in the planning period will be dominated by the primary processing industrial sector, farming, holiday homeowners, a few lifestyle blocks and distributed generation demands. These are highly unpredictable. This, coupled with both the low existing return on the network assets and the unwillingness of many customers to pay more, means that investment in growth normally occurs once customer commitment to load growth becomes certain.

The unpredictability of the investment due to customer growth means that the difference between medium and long term forward predictions and actual will vary. Assets needed to support a customer's specific need can only be added when customer contractual details are confirmed.

The biggest changes likely in the planning forecasts will come from distributed generation, industrial, holiday homes and farming development.

The time scale needed for projects to be completed is also increasing due to a whole host of reasons, including landowner awareness, regulatory consenting and available skilled resources.

It is recognised that the accuracy of short to medium term plans is better than the long-term projections. TLC has however put considerable effort into trying to get the best long-term picture possible of future network expenditure and the justification for this. This is required for pricing continuity, i.e. the need to minimise stepped changes.

Table 2.1 lists the expenditure categories as per disclosure requirements and outlines the level of detail taken into consideration in preparing estimates within the various timeframes.

LEVEL OF DETAIL AND EXPECTED CAUSES OF FLUCTUATIONS IN ESTIMATES	
Disclosure Expenditure Category	**Recognition of Accuracy**
Capital Expenditure	
Customer Connection	Difficult to predict. Driven by all levels of economic activity.
System Growth	Affected by customers. Predictions reasonably accurate for the next 5 to 10 years given present constraints identified by network studies. Is dependent on forecasts. New technologies such as advanced networks and small scale generation may also impact on this.
Asset Replacement and Renewal	Reasonable level of accuracy for the next 5 to 10 years. Data out to 2027 also contains a reasonable level of accuracy. Variation will come from levels of hazards and risk stakeholders are willing to accept. (The estimates are based on the general condition known and determined by patrols of the assets. Detailed estimates are put together one year out.) Estimates for line renewals are generally based on 10% of poles in first 15 year cycle needing renewal. Analysis shows that approximately 30% are not compliant with strength codes. If stakeholders want the 30% replaced, costs will be greater than the estimates included in this plan. Generally, estimates should be within ±10% for the next 10 years and ±15% for remainder of period.
Reliability, Safety and Environment	Estimates out to 2027 are based on specific jobs and projects. Variation will come through the need to do something before planned dates because of failure or other issues. Because estimates are based on specific detail, accuracy levels will be relatively accurate, i.e. within ±10%.
Asset Relocation	Estimates are difficult due to the six months or less lead time (generally) associated with the need for alterations for road works and the like. The amount of expenditure however is not significant.
Operational Expenditure	
Routine and Preventative Maintenance	Estimates are based on present activities. Activities are known for next 5 years. Beyond this, various issues have not been detailed or studied at this time. For example, more work is needed on analysing the effects of the renewal programme on maintenance costs in the medium term.
Refurbishment and Renewal Maintenance	Estimates based on present levels and future renewal plans. (Definition on the actual detail of what can be included in this expenditure category will cause the greatest variation.)
Faults and Emergency Maintenance	Expenditure will fluctuate, mostly dependent on the weather. Over time, estimates are based on average expectations and the assumption that renewal and vegetation programmes will reduce fluctuations.

TABLE 2.1: LEVEL OF DETAIL AND EXPECTED CAUSES OF FLUCTUATIONS IN ESTIMATES

Note: Estimates have been prepared based on the performance targets included in Section 4. The estimates and performance expectations align with the asset management strategy that takes into account the lifecycle of assets, asset types and asset systems. The above assumptions are based on present project approaches. One of TLC's objectives for the coming period is to complete this work at a lower cost by trying to do things like reducing the amount of live line and generator by-pass work.

2.4 Stakeholder Interests

In developing the Asset Management Plan, TLC has taken into account the interests of the following key groups.

2.4.1 Shareholders

The interests of our shareholders are identified through the Corporate Review process and other consultation. Although our shareholders hold different percentages of ownership, they have some common interests and some that are of greater priority for the major shareholder.

Both are interested in:

- The business being sustainable in the long term and the asset management strategies to achieve this.
- A reasonable standard of service being given to customers.
- The price to customers being equivalent to that charged in other rural areas.
- Customer satisfaction and fair treatment.
- A network that meets acceptable industry hazard related risk standards.
- A network that meets environmental and efficiency expectations.
- The development of innovative solutions, focused on reducing hazards, maintaining reliability and promoting customer choice including demand side management.
- The asset management strategies and plans communicated to them.

The major shareholder is also interested in:

- An acceptable return being earned from the assets.
- An acceptable cash return from the network, as the only way beneficiaries have of receiving benefit from their ownership is by way of a regular cash return. (Beneficiaries leaving the area cannot cash up any capital growth they have funded while with TLC.)
- Customers and community acceptance of The Lines Company activities including the asset management strategies and plans communicated to them.

It is considered inequitable that current customers be asked to fund upgrades from which they will receive no benefit. It is also considered inequitable if current customers do not contribute to renewal network expenditure from which they do receive a benefit.

The above interests are not achievable if revenues are limited to below an acceptable return.

The above interests are accommodated in the Plan by:

- The requirement that any customer-driven development work produces at least its cost of capital.
- Funding development work that is expected to produce future revenue by debt, rather than reducing cash returns to existing customers.
- The performance targets (SAIDI 300 minutes, SAIFI 4.86 frequency).
- Strong, but targeted, re-investment in renewals to provide a long-term hazard controlled and sustainable network.
- Charging systems that give choice to customers.
- This asset management plan and the related strategies.
- Communication of the key parts of the asset management plan and related strategies.

TLC's ability to earn an acceptable return on our assets was constrained by the previous regulatory regime and, going forward, the new regulated threshold defines an acceptable return. The organisation can limit investment in new customer driven work if acceptable returns cannot be earned. Investment in existing assets is however a sunk cost.

Balancing the customers' ability to pay against the need to reduce hazards and risk is not straightforward and is driven by priorities. The mechanisms for determining and managing these priorities are outlined throughout the Plan.

2.4.2 Customers

The interests of our customers are identified through direct discussion with large customers, meetings with customer representatives (e.g. Federated Farmers), regional level focus group discussions, and day to day customer feedback. Customers are interested in:

- Receiving a secure and reliable supply of known and agreed quality.
- Receiving timely information that enables them to know the service they can expect from our network so that they can plan accordingly.
- Receiving up to date information if an outage occurs on the network so that they can plan accordingly.
- Being charged a fair price, with information to justify that price. (Individually most want to pay the least amount possible whilst the present quality is either maintained or improved.)
- Long term, the lowest charges possible for present and slowly improving quality.
- Receiving information updates on the state of what is being done to ensure the network infrastructure is hazard controlled and sustainable. i.e. appropriate communication on the key issues, impacts and strategies in this plan that are likely to effect them.
- Having choice to reduce charges by reducing demand/energy use and improving power factor.
- Having clear claim and compensation systems when TLC assets do not perform.
- Having several pricing options available.

The above interests are accommodated in the Plan:

- The reliability targets that have been developed to be as focused as possible.
- By performance targets, including the asset group based performance targets (and evaluating gaps in this performance), to ensure each customer is receiving the promised standard of services.
- Re-investment in renewals.
- Strong customer consultation and information commitment including mechanisms to communicate key issues, impacts and strategies in this Plan that are likely to effect them.
- Direct customer billing, including a move away from energy to demand based charges for all customers. This signals demand, leading to fairer charging of customers and better asset utilisation.
- Supply point and density based pricing structure.
- Dedicated asset charges.
- Developing several pricing options to give customers more choice.
- Rules for payment of compensation being included in the Terms and Conditions of Supply.
- Keeping community groups and leaders informed on issues.
- Establishing and maintaining regular meetings with customer focus groups.
- Engaging local community people to assist customers understand demand and other charges.
- Engaging local community people to assist TLC follow-up and resolve customer concerns.
- Developing customer focused systems and processes throughout the organisation.
- A long term focus on energy efficiency and innovation.
- A charging system that encourages retailer competition and minimises the opportunity for additional retail pass through margins to assist in giving customers the lowest possible combined line and energy costs.

Conflicting interests occur when customers expect good service at a fair price, as well as a continued distribution by shareholder trusts. Customers tend to judge the efficiency of the company from the size of the distribution and charges. Some have had trouble understanding demand based charges, and separate lines and energy bills. The demand based charging system, however, does pass on cost signals and will facilitate lower long term charges than line charges based on volumetric energy.

A large number of systems are used to manage these conflicts, both internally and externally. These include:

- The Commerce Commission rules and regulations.
- Electricity Authority rules and regulations.
- Other legislation and regulations.
- Complaints resolution organisations.
- TLC's Trusts.
- TLC's Directors.
- TLC management.
- Customer advisors.
- Presentations to customer groups explaining TLC's pricing methodology.
- Customer clinics and focus groups.
- Development of a customer communications section within the organisation.
- Various independent reports on the charging structure that include recommendations on how these should be modified going forward.
- A customer submission and submission hearing process held during September 2011.
- Development of pricing options following this meeting.
- Acceptance of an asset strategy to roll out advanced meters to all customers across the network.
- Information coming from independent bodies such as the Commerce Commission and MED (Ministry of Economic Development) that compare TLC's operation with other networks.
- Independent load projection data that shows TLC's predictions reconcile with independent assessments (particularly Transpower).
- A strategy going forward is to develop an advanced network aligned to a rural environment.

2.4.3 Employees

The interests of our employees are identified through direct discussion with them and their representatives. Our employees are interested in:

- Advanced knowledge of work requirements so that they can plan their lives.
- A network and working practices with acceptable hazard related risks so that they are not harmed.
- Fair remuneration.
- Enjoyable work.
- Being part of an organisation with a positive culture.
- Having a clear purpose for coming to work and "making a difference" for the benefit of customers and their personal development.

The above interests are accommodated in the Plan by:

- The high priority given to eliminating or mitigating hazards.
- Advanced planning of work.
- The recognition that our staff have unique skills, associated with a rural network in a rugged environment.
- Creating a positive work environment that creates a high level of self worth.
- Communicating the long-term Asset Management Plan and Statement of Corporate Intent to them so they can understand company direction.
- On-going development of innovative techniques and work practices.
- Supporting personal development and training.
- A continuous improvement asset management strategy driven by this plan.

Conflicting interests occur when individuals or groups of employees have a different vision to that of the company or disruptive personal behaviour.

These conflicts can be managed by:

- Communication and discussion including the asset management strategies and actions included in this plan.
- Management techniques and systems.
- Unions.
- In extreme cases, disciplinary procedures.

2.4.4 Transpower

Transpower's interests are identified through communication and direct discussion. Currently Transpower is interested in:

- Protection of its Grid and the electricity system from harm caused by generation investors and load customers who are connected to the TLC network.
- Receiving revenue from TLC.
- Building capacity to meet present and future loads.
- Complying with regulatory needs.
- Improving public and industry perception.

The above interests are recognised in the Plan by the sums we have programmed for expenditure due to anticipated growth in distributed generation and load. A significant proportion of this is to ensure the protection of the Grid.

Conflicting interests occur when Transpower's systems and policies do not fit with TLC's or its customers' needs. These conflicts are managed by researching Transpower's polices and negotiating a solution that best fits TLC's needs aligned with this AMP. A continuous asset management initiative is to better align TLC's and Transpower's asset management strategies and plans to create better outcomes aligned to both organisations strategies. An essential part of this will involve the communication of asset management strategies. It should be noted that the Electricity Governance regulations often make Transpower's position more difficult in terms of negotiating a win-win solution for things such as transformer renewals and reactive power flows at the grid interface.

2.4.5 Contractors/Suppliers

Contractors' interests are identified through direct discussion. Currently they are interested in having:

- A secure work programme known sufficiently in advance so that they can plan their resource allocation.
- A network and working practices that align with industry standard SMS hazard related risks, so that their staff members are not harmed.
- A profitable work stream.
- Prompt payment for goods and services.
- A customer with a clear vision and defined needs so they can focus on producing the outcome, not researching what the outcome will be.

The above interests are accommodated in the plan by:

- The high priority given to eliminating or mitigating hazards.
- Advanced planning of work, particularly commitment to a long-term asset renewal programme.
- Developed practices for receiving and paying accounts.
- An asset strategy/plan that communicates supplier requirements.

Conflicts occur with suppliers and contractors over price and quality of services provided. These conflicts are normally managed by informing the suppliers of the issues. If they do not respond, an alternative supplier is used or payment can be withheld.

2.4.6 Landowners

Landowner issues are identified through discussion with their representatives (e.g. Federated Farmers), individual landowners, Maori landowners/trusts, customer service inquiries, landowner complaints and the pre-access land notification process. There is also feedback from the customer communications and consultation processes.

Currently they are interested in:

- Protecting areas of heritage value.
- Protecting amenity value.
- Having their property treated with respect.
- Protecting property values.
- Having an electricity supply at a competitive rate, suitable for the activities on their land.
- Protecting cultural values especially with long tenure Maori land.
- Clear understanding of asset management strategies and plans that affect their land.

These interests are, in parts of the Plan, recognised directly; however, it is more likely that they are not specifically identified but are part of the background ethos. Landowners, where supply is provided, are ultimately responsible for TLC charges. Conflicts occur mostly over charges, land entry, vegetation and lines on private property.

Cost conflicts are managed by using cost reflective charge rates and polices. It is important that TLC takes a consistent, but fair approach. The line charge rates are regulated by the Commerce Commission. The terms and conditions of supply that effectively apply these rates have been developed in consultation with customers and other stakeholders.

Land entry rules are covered under the Electricity Act and Regulations. TLC manages land entry in compliance with these.

Vegetation is managed in accordance with the Tree Regulations, the law of nuisance and rural fire regulations. Communication of the asset management strategies and intended actions minimises conflicts and is an important element of this plan.

Lines on private property are managed in accordance with the Electricity Act and Regulations. TLC often involves the regulator (Energy Safety) in these conflicts because it is not TLC's responsibility to enforce the legislation.

Conflicts outside of these most common issues are managed by negotiation and communication.

2.4.7 District Councils

District Council interests are identified through direct discussion. Currently they are interested in having sufficient infrastructure development available so that:

- Growth in their community is not hampered.
- Civil Defence capability is maintained.
- Access to the road corridor is managed appropriately.
- The electrical infrastructure delivers an acceptable electricity supply.
- Customer dissatisfaction is minimised.
- Asset management strategies are aligned to minimise reworking of road, footpath, and other services and disruption of further infrastructure assets such as water, sewerage and public lighting.

Having sufficient infrastructure is accommodated in the Plan by the requirement that any customer driven development work we undertake produces our cost of capital at least.

The Civil Defence requirement is accommodated in the Plan by identifying the risks, having plans in place to control these and being involved in various emergency preparedness planning groups.

Access to the road corridor is accommodated in the Plan via the inclusion of allowances for forward spend plans and by virtue of having the AMP. The AMP is used to communicate and detail when works are proposed.

Having infrastructure that produces acceptable quality of supply is accommodated throughout the Plan as is the need to manage assets to give acceptable levels of service.

Conflicting interests occur when District Council systems and policies do not fit with TLC's or its customers' needs. These conflicting interests are managed by researching council policies and negotiating a solution that best fits TLC's and each Council's needs/policies. These solutions are either presently included in the AMP or are included during the next review.

2.4.8 Regional Councils

Regional Council interests are identified mostly by correspondence and written information. Regional Council interests include protecting the environment and ensuring adequate emergency response. These interests are recognised in the environmental and emergency response sections of the Plan.

The contact with regional councils is not extensive; however this Plan is used to communicate TLC's asset strategies and policies.

Conflicting interests occur when Regional Council systems and policies do not fit with TLC's or its customers' needs. These conflicting interests are managed by researching council's policies and negotiating a solution that best fits both TLC's and each Council's needs. These solutions are either presently included in the AMP or are included during the next review.

2.4.9 Central Government

Central government's interests are identified mostly by internet correspondence, written information, meeting with officials, and legislation.

Central government interests include ensuring that a reliable fairly priced, supply of electricity is available to the King Country and Southern Waikato regions and that the network has acceptable levels of hazard related risk. These bodies are aware of the existence of the AMP and often refer to it in communications that occur between the groups.

The interests are recognised through compliance, submissions and the direction required by the authorities. Conflicting interests occur when laws, regulations, policies and codes do not fit with TLC's or its customers' needs. These conflicting interests are managed by researching the government's position and negotiating or complying in a way that best fits TLC's needs.

Feedback from these interactions is included in this Plan and the on-going development of asset management plans and strategies.

2.4.10 Retailers

Retailers' interests are identified through industry papers, communication and direct discussion. Retailers are interested in selling energy to customers that produce profits. They like to have simple to apply pricing options via automated billing systems. They also want advanced metering systems that have a long term benefit of reducing their operating costs.

The above interests are accommodated in the Plan by TLC's direct billing programme. TLC's interaction with retailers has reduced since the introduction of direct demand based billing.

Retailers are aware of this Plan, but generally they have little interaction. They are communicated to about the asset management strategies associated with legacy relays (currently in the regulated asset base), and advanced meters (currently outside of the regulated asset base).

Historically, conflict occurred with retailers over payments associated with this group collecting TLC's charges but repackaging them so that TLC's cost signals were not passed on to customers. There were also conflicts over the volumetric energy quantities transported and thus how much a particular retailer should pay TLC.

Continuing to work through retailers would not pass onto customers the demand side management signals TLC required. Meter reading data and customer details were also very inaccurate. TLC has managed this conflict by decoupling from retailers and introducing direct billing and demand based charges.

TLC continues to work with retailers, including communicating the relevant contents of this Plan. TLC has representatives on industry working groups associated with pricing and retailer interfaces. This Plan is used as the basis for communicating TLC's asset management strategies to these industry working groups.

One of the frustrating areas of conflict coming out of retail operations is data accuracy associated with energy transported. There seems to be a level of volatility when the amounts of energy sold to customers is compared on a year by year basis. Most of this appears to be associated with non-technical losses. The most likely source of this error is the accuracy and timing of meter readings. Long term, the rollout of advanced meters in line with this plan should eliminate this.

2.4.11 Maori

Maori interests are identified through discussions with various groups. To date there has been little thought given to the impact of electricity distribution on cultural values. Maori are interested in having supply available in their homes and Marae, which are sometimes located in very remote areas. Often they have access to few resources to fund these services. Maori groups also hold significant tracts of land in the King Country. Development of these is a key to generating future funds for the owners.

The Maori interests are accommodated in the Plan by the overriding objective of maintaining supply at the lowest possible cost whilst meeting quality expectations. The Plan also includes a commitment to use local labour as far as practicable to create income for people who may live in remote areas.

The Plan accommodates the development plans of Maori landowners who wish to create income for their families. Relevant parts of this plan and associated policies/strategies are communicated to Maori so that their needs can be aligned. Feedback and inputs are used during the review periods and some significant project alignment strategies have been achieved. Examples are Mokai Energy Park, Wairarapa Moana farm development and modification of renewal works in the Turangi area.

2.4.12 Distributed Generation

Distributed generation investor interests are identified by way of new connection applications and the issues associated with the continuing operations of existing plant.

Distributed generation investors are interested in:

- Connecting new plant at the lowest possible cost.
- Operating plant at peak capacity when energy sources are available.
- Having on-going costs as low as possible.
- Minimising their investment in engineering resources to research potential problems and develop solutions.
- Maximising their share of transmission avoidance credits.
- Minimising investment in connection equipment.
- Minimal planned and unplanned outage events.

The above interests are accommodated in the plan by:

- Detailed information on existing larger connections and the implications of these.
- Technical detail on the general implications of distributed generation connections in Section 5.
- A list of the conditions that must be fulfilled before connecting distributed generation equipment.
- Not acting as engineering consultants for generators by setting guidelines only. Generation investors are invited to employ consultants to find innovative solutions to meet the guidelines.

Conflicting interests occur when the drive of distributed generation to minimise investment results in costs that must be borne by load taking customers.

TLC's asset management strategies and pricing strategies resolve this conflict by being cost reflective. This strategy ensures generation investors receive maximum returns when plant is sized and built in an effective and efficient way.

2.5 Conflicting Interests that are Common and Affect All Stakeholder Groups

2.5.1 Hazard Elimination/Minimisation

Experience has shown that all stakeholders want a network, as far as practically possible, with an acceptable minimum level of hazards. Determining what is a hazard is not black and white and is constantly evolving as time goes on. As events occur, and expectations advance, safety codes are repeatedly re-written and re-drafted. This means that equipment, which was considered acceptable when installed, has over time been eclipsed by changed and improved modern equivalents. Technology has moved forward over time.

When growth occurs in a network, equipment is constantly replaced and updated. In the TLC network a lack of growth has meant that much of the old legacy equipment has aged and not been replaced as part of the natural growth cycle.

This leads to conflict between funding hazard elimination/minimisation work, and other renewal and capital expenditure work.

Fortunately, much of the renewal associated with hazard elimination/minimisation also improves security, reliability, and general network capacity. Available resources (particularly funding) tends to dominate the conflict as to how much can be done at once. (This funding is associated with the available revenue).

The conflict between an acceptable and unacceptable hazard is based on:

- Observations of obvious problems.
- Industry accident reports.
- The various Acts, Regulations and Codes that control the industry.
- The principles of equipment operation and the potential risk levels when things go wrong.
- Experience from investigating and being involved with various industry incidents.
- Review of equipment by suitable qualified and experienced professionals.
- Audits by the Energy Safety Inspectors.
- Asset management policies that promote a sustainable network including strategies/polices that take into account the lifecycle of assets and asset types.
- Feedback inter-relationship with the Safety Management System.

2.5.2 Electricity (Continuance of Supply)

Most stakeholders want TLC to have the lowest charges possible. The most significant influence on charges is the cost of maintaining and renewing rural lines.

The Electricity Industry Act 2010 was enacted and, amongst other things, repeals Section 62 of the Electricity Act 1992. Hence legislation now requires supply to be maintained to rural areas beyond 2013 via existing supplies or alternative supplies.

There was a change in the definition of the place to which supply has to be maintained. The funding for maintaining supplies has to come from other customers connected to the network.

Most remote rural lines were funded through a national Rural Electricity Reticulation Committee (RERC) levy on all electricity users. Research of TLC's, and national data, shows that about 1700 km of TLC's current 5000 km of lines were constructed using RERC funding.

Most of these lines were built in the 1950's as part of farm development for returning soldiers from World War II.

In TLC's case, the majority of these lines were constructed using sections of second hand railway track as poles. Most of these railway iron poles have given 50 years service as rail tracks and a further 60 years plus as power poles. Many are now in poor shape.

Many of the rural lines were constructed by farmers, and there was little design detail. This has meant that many are low strength and do not comply with present codes. Many are SWER systems that have always had greater loadings than the codes of practice specify as the maximum acceptable limits. SWER lines, because of the way they work, are inherently higher risk than two or three wire systems.

TLC completed an exercise confirming the lengths of uneconomic lines in 2009. Lines were considered uneconomic if the load connected is less than 20 kVA per customer (ICP) and the customer density is less than three customers (ICPs) per km. This is the criteria as prescribed in the 2001 ODV handbook issued by the Ministry of Economic Development.

The network was analysed on a feeder-by-feeder basis. The customers in each of the uneconomic segments were also individually identified and the income and demand from them was summed.

The associated analysis showed the total assets required to supply these customers equated to 31% of the total asset value and produced 13% of the income. Time has elapsed since this work was done; however, the percentages of assets used to indicate the income required for supplying remote areas will have remained largely unchanged.

Further analysis showed that economic customers would have to subsidise the uneconomic customers by between 25% and 50% under the legislation. The amount would depend on the extent of cross subsidy.

Many of these rural lines supply national infrastructure in the way of repeater sites. Figure 2.1 illustrates one such site about 10km North West of Taumarunui with approximately 14 repeaters covering all types of essential services.

FIGURE 2.1: ILLUSTRATION OF HILL WITH NATIONAL AND LOCAL INFRASTRUCTURE

The actual costs of renewing the segments individually included in the long-term Plan have not been calculated or reconciled in detail at this time. In general terms however, the cost impact of renewing these lines is about $2m annually.

The Act gives the option of alternative supplies for these areas. The difficulty with this is that these technologies are not advanced enough to supply most of these customers with the convenience of grid connection. Alternative power supply systems involve batteries, generators, etc. that need fuel and regular maintenance. Generators generally burn petro chemicals, make noise during operation and have limited life spans.

Plugging equipment into a grid supply is a much more convenient option for busy farmers. A similar situation applies to larger radio repeaters and water pumps in rural areas; alternative power supplies are not a realistic option at this time.

The conflicting interest options for TLC to fund this renewal are:

- Cross subsidies from economic residential, small commercial and holiday homes by about 50%.
- Cross subsidies from industrials to uneconomic customers.
- Charge uneconomic customers full costs.
- A combination of above.

Any of the options are difficult. Holiday homeowners do not want to subsidise rural property. Industrials do not want to subsidise rural property. It may drive them from the area. Uneconomic areas include many lower income communities. Accommodating the conflicting interests is difficult and TLC is, at this time, focusing on developing its demand side management approaches to try and minimise the impact on rural customers.

The focus on the present to medium term is renewal; beyond this time, development will become the focus. Unless there are price adjustments, TLC will have difficulty doing both.

The introduction of separate billing has seen retailer price movements that are less than the rest of the country. The make-up of TLC's lines charges gives customers the option of reducing their costs through moving load without substantially affecting their lifestyles. Controlling demand and not needing to upgrade (for example, SWER systems) will have a long term saving on TLC's pricing to rural areas.

The need to maintain remote rural lines that were built with RERC subsidies, but now have to be renewed without them, is central to TLC's asset management challenge. This point has been communicated to all stakeholders including officials employed by regulators (many of whom have visited our area), customers, trustees and various lobby groups as part of TLC's asset management process.

2.5.3 Supply to Holiday Home Areas

There was a conflict between our shareholders requiring an adequate return on assets (but the revenue being received from holiday areas being well below what was necessary to produce a return) and belief by holiday homeowners that consumption based charges was a fair way of pricing. The previous way of managing the conflict was to reduce the level of investment. However this produced a service level that customers were not happy with. When holiday homeowners were given information about the structure and level of our costs and how they influenced them, including the Transpower peaks, overall their view of what a fair price was changed. This enabled us to introduce demand charges, which in turn enabled us to increase our investment in these areas with a resulting increase in service provided.

The energy based higher holiday home charges were superseded by the demand charges. Now holiday home owners pay for demand at the same rates as other customers. Holiday home owners, as a group, generally accepted demand based charges.

It is accepted that some holiday home customers have difficulty understanding the receiving of separate accounts for line and energy services when comparing this to charges for other properties they own. Most understand the separation when it is explained to them via the call centre or in consultation with customer advisors.

During mid-2011, two independent reports became available on the options TLC has for recovering revenue fairly from holiday homes. An extensive consultation process based on these reports was undertaken as part of the organisation's focus on asset management and getting funding to manage assets through their lifecycles in a long term sustainable way.

2.5.4 Asset Renewal

Our shareholders require that their investment returns TLC's cost of capital. Customer beneficiaries were not willing to lower cash returns received in order to fund network upgrades. Customers were unwilling to meet high price increases. Both groups want a sustainable network and improvements in reliability.

This conflict is met through a targeted renewal programme, which ensures that the network does invest in assets, and a programme to ensure that reliability is improved with minimal network investment.

Innovative practices also play a major part in aligning these interests. Time is spent communicating and justifying the need for renewal expenditure with stakeholders. This includes customer, media and community leader presentations, and site visits. On these visits, the hazards and risks are discussed along with the costs associated with eliminating/minimising these.

The TLC network, because of its age, requires considerable investment.

Stakeholders have, in recent times, accepted lower levels of return mostly due to an increased awareness that assets need to be renewed.

Looking forward however, there is a difference between the Plan's predicted asset renewal spend and revenue per Commerce Commission models. This difference is largely the returns to shareholders (dividends). Some stakeholders, particularly the minority shareholder, is having difficulty accepting this given the customer pressure they endure.

This is one of the issues that on-going discussions and consultation between Directors and stakeholders are addressing. This is a high level communication on the realities of shareholder return associated with investment in assets and the management of these assets in a sustainable way.

2.5.5 Retailers

Retailers want to take network line charges and repackage them as part of their marketing strategy. This masks customers' understanding of TLC's function and the services that line charges fund. It conflicts with TLC's and their stakeholders' objectives, who feel charges should reflect the cost of supply. Retailers can also add a margin for line charges onto customer accounts and keep penalties for late payments. This also negates demand side management messages that TLC wishes to pass on to customers.

To remove such negative influences, TLC charges the customers directly at a cost that is lower than margins charged by retailers for collecting TLC's revenue. This strategy places TLC in direct communication with customers regarding revenue and asset management and makes line charges totally transparent. This helps customers understand network issues and encourages competition amongst retailers. It also helps unbundle the issues associated with connecting distributed generation, promotes demand side management, signals power factor improvement needs and, along with numerous other benefits, improves asset utilisation.

This strategy is believed to have been part of the reason why retailers operating on the TLC network have not increased charges at the same rate over the last few years as retailers on the more densely populated networks.

Retailers are aware of the existence of TLC's asset management strategies and plans. They are only interested in the sections that relate to them and the associated interfaces. These are communicated to them as part of the asset management strategy.

2.5.6 Network Capacity Demand, Dedicated Asset Charges and Demand Side Management

Historically, networks based charges on transported energy and fixed components (and perhaps, demands). The cost of transporting energy has a demand and fixed component. TLC has changed the structure of all its line charges to better reflect costs by having separate capacity, demand and, where provided, dedicated asset charges.

The capacity charge is based on the anytime size of the capacity made available at the point of connection. The demand charge is based on the peak demand an installation takes during a network constraint or control period. The dedicated asset charge is for assets that are not shared by other customers. The advantages of this charging structure are numerous and discussed in various sections of the Plan.

The most significant of these advantages is that demand based charging passes on the major cost drivers for a network company. Consumption based charging does not. The effect of this is that long term prices under consumption pricing would have to increase at a faster rate than demand based charges.

Most of the conflict was caused by change and customers who saw charges increase. The most common cause of increased charges was the result of customers changing historically controlled load to uncontrolled and then not understanding why demand charges had increased. This conflict is being managed by customer advice and communication with the affected customers.

There was also conflict caused by TLC not having network-wide advanced meters and, as such, charges were based on calculations. This conflict will be managed going forward by deployment of more advanced meters.

The consultation between TLC and stakeholders at corporate and stakeholder level is focused on this conflict. An objective of this is to communicate asset management policies, strategies and plans to stakeholders. A likely outcome will be a series of pricing options based on demand, capacity and dedicated assets that give customers an improved choice.

Customers are accepting that demand based charging using advanced meters is the way of the future.

The customers who have had the asset strategies and plans communicated to them are understanding and supportive. One of the keys going forward is to give them more input and choice into how revenue will be provided.

2.5.7 Conflict between Customer Interests as Customers and Shareholders

As beneficiaries of the shareholding, customers get a dividend return. Some customers would prefer lower upfront charges or to see the money reinvested in the network. TLC believe that it is the responsibility of the Trustees, who are elected by our customers, to resolve this conflict by consultation and advice to the company through the Strategic Review process.

The shareholders did accept lower returns for the 2008/09 and 2009/10 years. From the 2010/11 year forward, prices were regulated and returns aligned with Commerce Commission guidelines.

As stated in earlier sections the *Commerce Commission Starting Price Adjustments for Default Price – Quality Paths Discussion Paper dated August 2010* and subsequent papers during 2011, indicated that TLC's return is below the Commission's expectation. Price adjustments will be a subject of debate with the stakeholders, along with which areas they should be targeted at. This is part of the extensive consultation that is currently taking place, and of the corporate high level asset management governance.

2.5.8 Conflict between the Requirements of Legislation and Customers' Wants

Legislation and regulations passed, particularly over the last 10 years or so, have often failed to achieve key objectives and have sometimes produced counter-productive outcomes. TLC have found that many pieces of legislation are difficult to interpret, and require frequent and costly legal advice. This makes it difficult for the parties to which the legislation applies and for others, especially customers, to understand and thus tends to suppress innovation.

The requirements of this legislation usually increase cost with little benefit to customers. For example, legislative regimes designed to promote improvements in areas such as environmental protection appear to do little, or nothing, positive but impose significant additional costs that flow through to customers. There are over 25 pieces of legislation that apply to electricity distributors.

There has been a trend over the last decade or more towards distancing Parliament from more technical or commercial decisions in areas such as industry regulations. Detailed implementation decisions, for example Electricity Regulations, are now being made by the Commerce Commission. The new Electricity Authority has been given direct regulatory powers. Some of the advantages of this approach have been offset however by the whole government oversight. For example, while the Commerce Commission has been focused on eliminating cross-subsidies, the Government Policy Statement on Electricity promotes cross-subsidies of rural lines, and various regulations require distributors to apply cross-subsidies to charges for low consumption levels etc. Existing political processes are likely to maintain this pattern of principle-based regulation, mixed with fairly haphazard populist interventions, without coherent overview.

There is also little cohesion or understanding of the relationship between the impacts of legislation coming out of the various government bodies. For example hazard control, quality and prices are closely related. These functions are split by the Electricity Act and the Commerce Act. Neither are focused on perhaps the most important long term issue, the environment.

Given the rural nature of the TLC network these conflicts are particularly pertinent. Managing the rural urban cross-subsidy using consumption based charges is not possible, particularly when the urban areas are generally low socioeconomic regions. The change to separated demand based charging was, amongst other things, seen as a way of managing one element of this conflict.

The asset management policies, strategies and plans TLC has in place are focussed on managing all of the "balls in the air" through asset lifecycles.

Once legislation is passed however, TLC's only option is to understand the rules and then set about developing strategies for compliance aligned to providing the best solutions for our stakeholders and asset management policies, strategies and plans.

2.6 Accountabilities and Responsibilities for Asset Management

2.6.1 Governance

TLC is owned by two trusts: Waitomo Energy Services Customer Trust (90%) and King Country Electric Power Trust (10%). The Waitomo Energy Services Customer Trust appoint Directors. The Directors are responsible to the shareholders for the overall performance of the company.

The strategic direction of the company is reviewed annually and submitted to Directors. From this, the company's Statement of Corporate Intent is developed. Both documents are closely aligned to the asset management policies, strategies and plans.

The Board of Directors considers and approves the Asset Management Plan. The key asset management strategies and projects (annual spend plans, the 2003 Reliability Plan, vegetation control strategies, charging policies etc.) are generally approved by Directors before incorporation into the Asset Management Plan document.

Trustees also read the Asset Management Plan and forward their support and any concerns relating to the document back to the Directors.

In addition to strategic approvals, Directors approve:

1. Development expenditure priorities and the business cases for development projects.
2. Overall annual renewal expenditure projects with detail available on a project-by-project basis.
3. Capital development projects.
4. All unbudgeted emergent work over a $50,000 threshold.

Expenditure against budget and explanations for variations on a category or project basis is reported to Directors monthly. Key system performance indicators are reported on a monthly basis. These elements form important parts of feedback on asset management plan performance.

2.6.2 Executive Level

The Chief Executive Officer is responsible for the overall performance and operation of the company.

The responsibility for overall network management, including the preparation, drafting, and all aspects of implementation of the Asset Management Plan, is delegated to the Engineering Manager. The Directors are kept informed and updated on significant issues. They also approve variations, caused by unpredicted work and customer demand, upwards of $50,000. The Engineering Manager is involved in the technical aspects of most commercial decisions and modelling of network income associated with the management of TLC assets.

2.6.3 Asset Management and Engineering

The Asset Management Plan, policies and strategies are used as reference and form the basis of asset management decisions. Decisions can be referenced back to this document.

Most asset management tasks, including asset inspection, is undertaken in-house. In this way, TLC can control the work on the asset so that the desired outcomes are achieved. Planned work is allocated to the in-house service provider. The finished work is inspected by Asset Management Group (AMG) staff to ensure that it meets acceptable hazard and quality standards.

The AMG group consists of the following staff:

- One qualified CPEng – REA, and Registered Electrical Inspector.
- One Senior Engineer – Degree qualified.
- One Design Engineer – REA qualification.
- One Network Performance Engineer – Registered electrician, Diploma of Engineering
- One Operations Engineer – Vacant at the time of writing.
- One Design Cadet – Degree qualified.
- One Network Performance Cadet – Diploma qualified.
- One Network Lines Controller.
- One Vegetation Co-ordinator.
- One Tree Administrator.
- Two Line Designers/Inspectors/Auditors.
- One Network Data Controller
- One GIS Administrator.
- One Control Room Operator.
- One Backup Controller/New Connection Controller.
- One Line Renewal Co-Ordinator.
- One Emergent/Fault Work Co-Ordinator.
- One Administration Officer/SMS Co-ordinator.

The current structure for this group is illustrated in Figure 2.2. It is likely to be amended in the near future due to a number of resignations, increasing compliance requirements and the need to do capital works at the lowest possible cost.

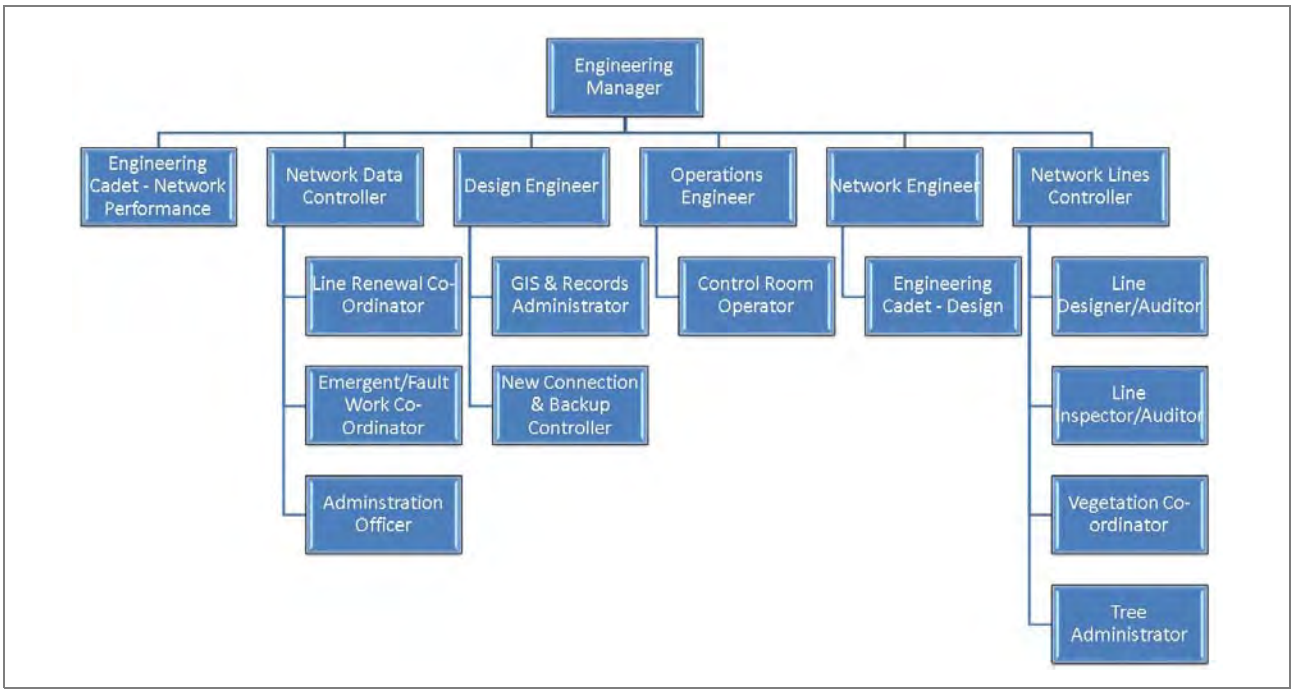


FIGURE 2.2: GROUP STRUCTURE

Specialist work such as SCADA (Supervisory Control and Data Acquisition) and communications is controlled directly by the AMG group. Specialist SCADA and communication contractors complete the work.

Vegetation work is controlled and issued by the AMG group to tree contractors who have the necessary quality and hazard control systems in place. These contractors include a local helicopter operator who provides a large proportion of the overhead line fault finding service.

The AMG group inspects and prepares detailed designs including regulatory approvals before forwarding line, mechanical workshop and faults activities to the service provider group. External drafting and engineering consultants are used when workloads are high. Specialist data, valuation and safety consultants are also engaged to assist as required.

The difficulty in recruiting experienced technical staff is recognised and TLC is currently sponsoring one graduate and will likely sponsor others in the future.

The Network Data Controller is studying towards a Diploma in Asset Management and this role forms a key part of TLC's asset management implementation, including asset management computer system development and overall consideration of the plan.

The staffing, the structure and the skills are aligned to the Plan to ensure effective and efficient implementation. The individuals within this team have various delegated authorities to implement the Plan. The supply chain logistics are handled by field service providers; however, specification of the actual items is completed by the Engineering and Asset group. This information is included in distribution standards and individual project details.

The delegated authority to asset and engineering staff includes a responsibility to communicate the Plan.

2.6.4 Field Operation Level

Maintenance and capital works (excluding vegetation and specialist technical) are issued to the internal service provider, which undertakes them with a mix of internal staff and outside contractors.

The Contracting Operations Controller is responsible for the contracting operations. He reports to a management committee made up of the CEO, CFO and the Engineering Manager. Regular meetings take place between senior contracting staff and the senior asset and engineering staff to ensure that the network's needs are being fulfilled.

The internal service provider operation is mainly staffed for faults response and carries out about 70% of the capital and maintenance works. It has about 50 staff consisting of supervisors through to utility workers. There are depots at Whakamaru, Taumarunui, Turangi, and Ohakune. The central depot and store are based at Te Kuiti.

The balance of the line capital and renewal projects are subcontracted to external contractors. The specifications for this work are prepared by the AMG engineers and allocated to the internal contractors as early as possible so that they can divide work between the internal and subcontracted staff. The use of external contractors provides a cost benchmark.

Due to the rugged nature of the local terrain, and the fact that many lines are off-road, niche techniques have had to be developed to reduce outages due to planned work. In-house staff are used for work where these skills are required; external staff tend to be used for the more common work (e.g. straight forward planned renewals).

It should be noted that Commerce Commission Decisions 685 and 710 will require the development of further niche techniques to meet quality threshold criteria.

As discussed in other sections of this Plan, the terrain and architecture of the TLC network make live line work difficult. The niche techniques being developed include the use of generators to bypass work sites and mobile reactive power capacitor banks to support the network alternative supplies.

The internal contractor must submit price estimates before major projects commence. Any excessive profit margins are removed from capital works before costs can be put against assets. Costs are benchmarked against external providers' work and industry surveys. A project has been initiated to add a calculator to the asset database that breaks down the latest industry unit rates into component amounts so that works controllers can see and compare the benchmark rates for various activities. Quotations and invoices for work from internal and external providers are currently reconciled to these benchmarks.

2.6.5 Staffing

TLC has difficulty attracting specialist staff to the King Country as the area is distant from major population centres. The strategy has been to employ a number of industry experienced and qualified personnel, and then use them to impart their knowledge in training local people. TLC is aware that intellectual understanding should be rewarded with competitive remuneration in order to retain skills. Most employees who settle into the local area, and become part of the community, are retained. Moving forward TLC's strategy to overcome the skills shortage will be to train an increasing number of local people. TLC has also undertaken a programme to attract local graduates to the organisation.

Due to the relatively small size of the network, staff have to be flexible and this leads to challenging work across more diverse activities than larger organisations might offer. Similarly the relatively low staff numbers mean all staff have a greater sense of worth than they would have working for larger organisations. The effects of individual efforts are more transparent.

The financial and administration section is responsible for billing the network services, administration and providing accurate and timely financial information.

TLC has been an industry leader with its separate billing for lines charges. This has led to some confusion and increasing communication with our stakeholders has a high priority. A Communications Manager has been appointed and she holds regular meetings with stakeholders to ensure good lines of communication are developed and retained.

2.6.6 Outcomes Reported to the Board

In addition to monthly financial reports to Directors, reports covering the key performance criteria (as included in Section 4 of this Plan) are submitted regularly to Directors. Additional reports are provided as required.

2.7 Details of Asset Management Systems and Processes, including Asset Management Information System/Software and Information Flows

2.7.1 Systems Overview

Since 2008, TLC has been rebuilding and refining its IT and database structure. The rebuild has resulted in three systems: a Financial System (Navision); Billing System (Talgentra); and an Asset Data System (BASIX). All have SQL server databases and data is being exchanged between systems. Figure 2.3 illustrates, in a very simplified format, the overall system layout and interaction.

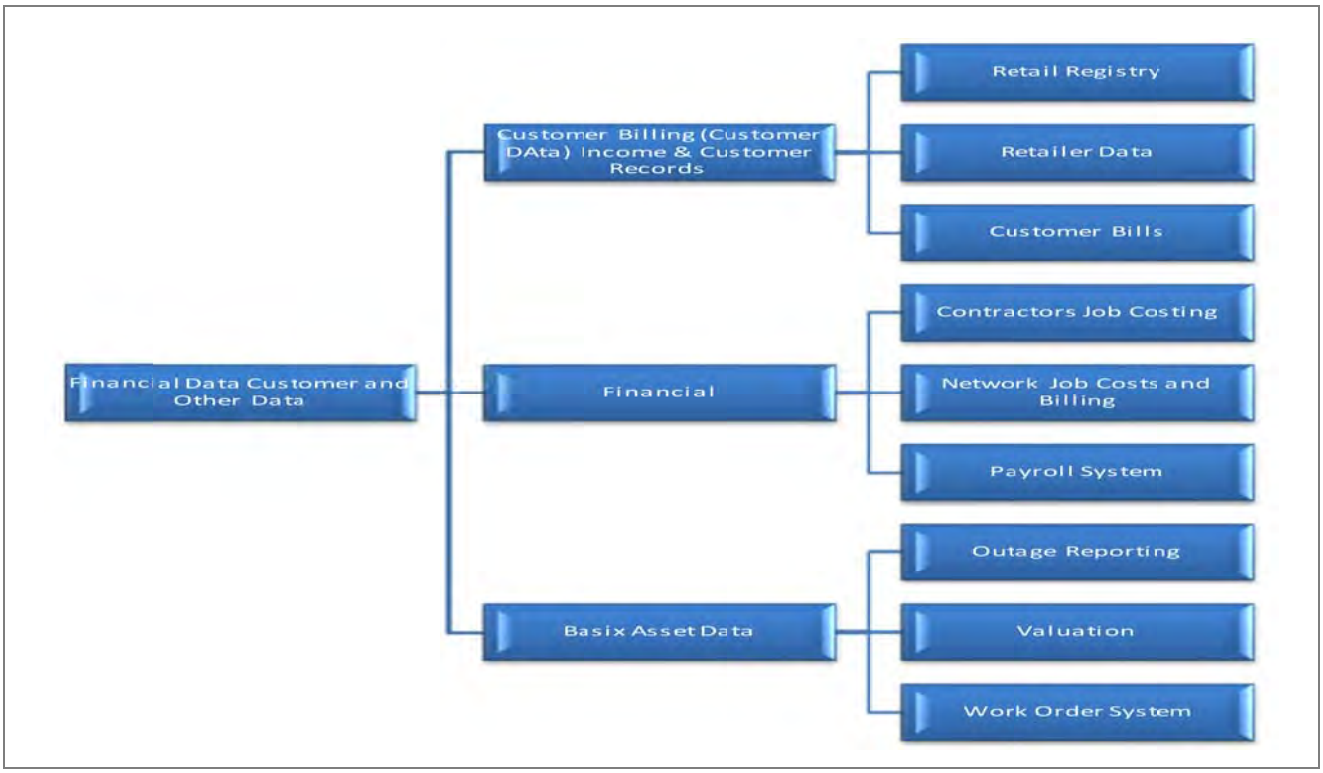


FIGURE 2.3: OVERALL SYSTEM LAYOUT AND INTERACTION

Setting up a stand-alone customer billing system with correct customer data and links to the financial and asset management has been a major undertaking. The process highlighted the incorrect retail data supplied by retailers. This was a major implementation obstacle and, effectively, all customer details had to be manually checked. The billing software is based on a heavily modified Talgentra system over an SQL server database. The "off the shelf" volumetric traditional billing system had to be modified to an extent far greater than originally envisioned to cope with demand based billing.

The financial system is based on a Navision software package over an SQL server database. In addition to processing and providing financial information for the various companies associated with TLC, it includes detailed job costing packages. The financial system is stable, but further development is needed to give the low level detailed reports required.

The asset management system is based on BASIX software over an SQL server database. The BASIX system has been developed over the last 4 years; it now contains asset data and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in Section 4 and Section 8 of this Plan. The system is being extended further to include asset related customer service data.

The BASIX system is also used for many other asset related activities as detailed in subsequent sections. There has been a considerable amount of progress on the development of the system over the last 24 months and there is an extensive amount of development planned going forward.

The work undertaken over the last 12 months includes:

- Valuation calculations rewritten to reflect the changes that Commerce Commission Decision 710 has required.
- Valuation reporting modified to enable values to be dissected for different requirements.
- Other minor developments to make system use easier and the information available more reliable.
- Integration between Talgentra and BASIX.
- Commencement of a project to get LV connectivity down to ICP level.
- Annual Planning spread sheets being transferred into BASIX.
- Tools for entering all incoming network customer 'no power calls' and linking of these to asset fields.
- Initial development of a customer focused outage notification system.

The work planned includes:

- Works price calculator within the database to break down components of a job so that the cost estimates can be compared to national benchmarks.
- Further breakdown of network complaints and reporting.
- Other customer service related developments.
- Other reports and data required by the Commerce Commission as part of a quality CPP submission.
- Other system development to gain more efficiency.
- On-going development of a Safety Management System data and information for compliance with the Electricity (Safety) Regulations, 2010.
- Development of the job control system to allow forward spends estimates to be put into the package and link projects. The objective of this is to empty further data silos sitting in spread sheets. This development will be relatively complex in terms of reporting requirements, in particular those required to provide links with the accounting system and Commerce Commission reporting.
- Investigating and preparation of specifications for putting a mapping system over the top of asset data using a low cost modular package.
- Setting up a linked section to receive and store meter and relay data as part of the development towards an advanced network.
- Capture of low voltage data.
- Modification for changes to Commerce Commission disclosure requirements.

Assets are broken down into components (for example, lines are broken down into poles, cross arms and spans) and photographs are attached to these records. The asset type, capacity and condition are recorded along with a considerable number of other data fields.

Assets are layered in many dimensions into components, items, segments, asset groups, density bands and service level groups in addition to categories, feeders, zone substations, distribution asset class, supply areas etc. Age is a key criterion for calculating depreciation and other reporting.

Currently TLC has an ESRI GIS system (mapping package) that has been operating in a "stand-alone" mode for the last few years. The next major development step is to integrate this mapping package, or an equivalent, with the other systems. The objective is to allow users to drill down into asset data from a map and allow asset data to be presented in a geographical format. To date carrying out this development has been a lower priority than the reporting required for network performance and compliance. Integrating however will lead to some (relatively minor) labour savings.

2.7.2 Financial Forecasts

An array of spread sheets were originally set up to generate the long-term work plans. The data used in putting together the long-term forecasts comes from the asset databases, photographs, and network knowledge. For example, the hazard elimination/minimisation section of the forward forecasts was put together and prioritised by looking at over 600 photographs of equipment and using a network overview of the alternative arrangements to determine priority. Equipment age, condition, environmental factors, location, and other factors were considered.

A complex series of linking and allocation masks were used over the top of the detailed spread sheets to group work into equipment categories and Commerce Commission disclosure formats. It was recognised that a more stable IT platform was required and the transfer of these long-term estimates to the BASIX system has now been completed. Looking forward, this will significantly improve TLC's asset management estimates and reporting processes.

2.7.3 Asset Data Accuracy

The data is stored in various SQL server tables that are viewed and written to by the various BASIX user interface forms.

Data accuracy continues to improve. The BASIX system is stable and is steadily being refined. Variances between actuals and the system held data are being corrected from work associated with renewals, maintenance, capital development and other asset checks. A project to improve the quality of LV data has been instigated and work continues to break assets into smaller items to improve detail.

The starting point for the transfer to the BASIX system was the 2004 ODV data.

The errors found at the time of transfer include:

- Records of poles and related span lengths not being correct.
- Asset age estimates of remote rural lines not being correct.
- Lumping of substation assets into groupings and when these are broken down the value of the individual totals sums to a greater amount, with a different average age.
- Items that had previously not been included, such as short lengths of cable between poles and ground mounted transformers.
- Private responsibility lines were included in the data.
- Poles and equipment that had been replaced having incorrect age information.
- Missed equipment, such as reclosers and automated switches.

These errors continued to be corrected and the effects flow into the annual regulatory valuation calculations made up until the 2009/2010 calculation.

It should be noted that assets will continue to be found until the entire network is inspected in detail as part of the 15 year renewal programme and other data collection projects.

Base data and models are now generally accurate in the following areas:

- 11 kV Lines and associated equipment.
- Transformers (overhead and ground mount).
- Line switchgear and equipment.
- Low voltage service boxes and link pillars.
- 33 kV Zone substations.
- 33 kV Lines.
- 33 kV Switchgear.
- Other technical equipment including SCADA.
- 11 kV cable and related equipment including switchgear.
- 33 kV cable and related equipment including switchgear.

In these asset categories, individual assets down to poles, cross arms and spans etc. are identified and capacity/condition is recorded. Accurate pole condition data including 2 to 3 photographs per pole are held for about 65% of the network. For the remainder, the accuracy is limited and based on the area and pole type.

Data is not accurate for:

- Low voltage overhead systems.
- Customer points of connection (i.e. 3 phase, single phase, underground or overhead).
- Low voltage underground systems.
- Street lighting.
- Some SCADA and communication equipment.

There are two main reasons for these accuracy variances. The first was the difficulty in understanding and recording data against the assets given the on-going changes of ownership boundaries. Legislation on ownership has been developing since the mid 1970's. The ownership of private lines has been, and in some case remains, complex. The best reference to get a better understanding of the issues is a paper on this subject produced by the Electricity Authority. The paper is available from their website.

The second is that data collection and records, to date, have focused on the 11 kV network. The low voltage systems have tended to be treated with less importance and accurate data has not been collected. This has also been partly caused by low voltage systems being more complex especially when integrated with underground systems; linesmen based data gatherers have tended to have difficulty with understanding and following the systems. Similarly SCADA and communication systems are not understood by linesmen data gatherers.

A focus is now being put on gathering this data. It will however take a number of years of gathering information before records are accurate unless additional resources to do this task can be funded.

In summary TLC data accuracy is improving and it took a major step forward with the transfer from old data systems to the BASIX system. Correcting and maintaining data is an on-going task.

The BASIX system includes a connectivity model that is used for outage reporting. As further discussed in subsequent sections, this model connects various assets together and then has a calculation that produces the regulatory performance indications. The physical processes required to set this model up and then maintain it resulted in data errors being found and addressed. Customer numbers are transferred automatically from the billing system on a regular basis.

The feeling of independent auditors of regulatory data confirm TLC's opinion that data inaccuracies have caused assets to be undervalued, not overvalued. The biggest risk to overvaluing comes from the costs of internal contractors doing renewal and capital expenditure work using live line and generator by pass approaches. The recently proposed Commerce Commission disclosure changes will also mitigate this risk if they are implemented. The development of a calculator within BASIX with data coming from national industry survey data is seen as a key strategy to minimise this risk.

2.7.4 Asset Management Information System and Data Structures

The BASIX system consists of various modules including:

- Asset Register.
- Business Entities.
- Works Management.
- Outage and Reliability.
- Reporting.
- Customer Service and other related assessment activities.

The asset register is used to access the network data and is broken down into:

- Lines.
- Installations.
- Zone substations.
- Transformers.
- Switchgear.
- Protection and Control.
- Network Model.
- Property.
- Batteries.
- SCADA & Radio
- Other tools and instruments.

Each of these asset categories is further broken down with a tree structure. Lines, for example, are further broken down into poles, cross arms, and spans. Figure 2.4 shows a typical screen shot of held pole data.

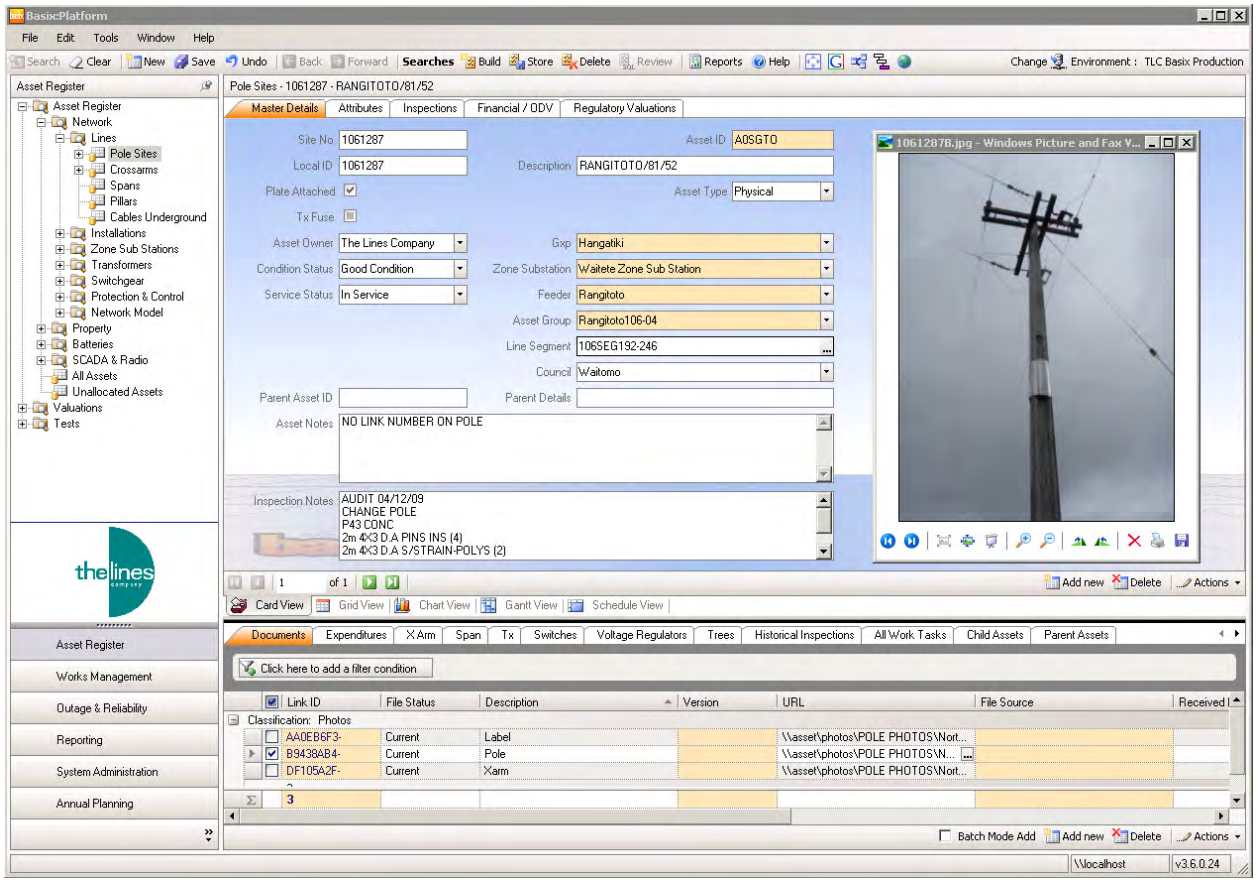


FIGURE 2.4: EXAMPLE OF BASIX POLE DATA SHOWING LINK TO ATTACHED PHOTO

Overhead lines and associated equipment are broken down into approximately six to ten asset groups per feeder. These asset groups are segmented in a way to control maintenance and are structured so that costs, faults data, billing densities and customer service criteria are linked. Poles are numbered and the type, assessed age and condition are recorded.

Photographs of each pole are taken and used for:

- Physical information of site and layout, pole type, cross arm configuration and other hardware. (Providing this to contractors reduces time and cost necessary to price and plan jobs.)
- A desktop second opinion when assessing condition.
- A flexible record for all types of information enquiry.
- Reference when processing new customer connection requests.
- Fault information.
- Other day to day operating and asset enquiries.

Works orders and estimated costs of works are raised in the BASIX system and put against assets. Cost information from completed jobs is also put against assets.

The BASIX system also includes a reliability calculator that is attached to the asset data. All data in the BASIX database is connected together in single line diagram format. A parent-child connection has been established between assets.

Data from the billing system gives accurate details of customers connected to each transformer. The reliability data is entered regularly and results are calculated. All historic outage data has been loaded into the BASIX system and is used for calculating reliability and previous historic data needs. The reliability calculator includes the facility to produce Commerce Commission Decision 685 information.

Root cause analysis is undertaken when components fail. Care is taken to recover as many of the damaged items as possible and these are examined in detail.

Protection, fault current levels and other technical detail are modelled using a network analysis package. Once the cause is established, a course of action is decided. Samples of recovered failed components are often labelled and stored for future reference.

Vegetation data is stored in the BASIX package and systems have been set up for compliance with the vegetation regulations.

TLC has GIS (Geographical Information System) software that is operating from its own database; it is not linked to BASIX at this time. The GIS program is mostly used to give geographical information of asset locations. The intent is to link it to BASIX and use a common database in the future. The GIS platform is ESRI Arc View. (Note: The linked program may not be ESRI.)

TLC is now undertaking all customer telephone answering services in-house, including calls outside business hours. The customer billing information is entered into the billing system. Network related issues are entered into the BASIX system. This information is placed against individual ICPs. From this it is possible to report on repeated fuse blowing events and the like and then reconcile this to billing information. The tool is used to identify customers who have understated the required capacity and this allows TLC to control its revenue risks.

Taking back the telephone calls has delivered improved customer services. Local knowledge in reconciling faults to customers, manually at present, has seen many network problems being addressed faster and more efficiently than before.

2.7.5 Processes for Managing Routine Asset Inspection and Network Maintenance

As part of the preparation of the annual Asset Management Plan review, TLC is continuing to add more detail to its long-term renewal and maintenance plans. The renewal and development expenditure plan lists expected renewals under lines (33 kV, 11 kV and LV), substations, distribution transformers, SCADA, communications, protection and switchgear renewal by individual jobs, items, and asset groups. Estimates are reported in equipment categories and Commerce Commission disclosure format.

The maintenance plan details activities for:

- Cables.
- Lines.
- Distribution transformers (SWER, Ground mount, Pole mount).
- Zone substations (Planned, Unplanned, Buildings, Oil etc.).
- Faults (33kV, 11kV, LV, Zone subs).
- Vegetation (Planned and Unplanned).
- Other technical equipment (SCADA, Communications, Reclosers, Protection, Regulators, etc.).

Both the renewal and maintenance plans extend to 2027 and report by asset class and Commerce Commission disclosure format. The projects involved and the reasons for them are described in detail in this Plan. A major driver for the need to establish forward expenditure trends with relative accuracy is for forward revenue predictions.

Because of the old network, TLC needed to get a good understanding of expenditure needs into the future. TLC is also facing issues such as the need to fund continuance of supply to remote rural customers beyond 2013 and the implications of being an organisation that is regulated under Commerce Commission legislation.

The long-term renewal and maintenance plan is on a year-by-year and activity-by-activity basis out to the end of the planning period.

The activities for each coming year are then extracted and reviewed. These form the basis of the annual plan for the coming year. The plan is adjusted when justified due to previously unknown environmental, customer, equipment and other issues, which mostly feed into the 1 to 5 year forecast period.

Over the planning period, all predictions and control will be transferred into the BASIX system. Ideally, projects should be controlled by a project planning package that allows linking of projects. At the time of writing, this has not been fully achieved but has been significantly progressed. The long-term plan flows down and controls the various asset inspections, network maintenance (renewals), planning and network development projects.

More detail is given on the specific processes for each asset class in subsequent sections.

2.7.6 Overhead Lines: Routine Asset Inspections and Network Maintenance

2.7.6.1 Planned Work

A 15 year rotation inspection programme is undertaken on an asset group by asset group basis, i.e. a time-based inspection programme. Experience has shown that pole conditions can be more accurately assessed for a 15 year period as opposed to shorter or longer time frames. The rotation also produces manageable work outputs. Further discussion on the justification for this programme is included in Section 6, Lifecycle Asset Management.

The asset groups to be inspected are identified by the long term plan. Gap analysis is used to compare service achieved with the promised service standard; other factors such as general condition, hazard related risk, environmental risk and the importance to the overall network integrity are also considered when determining the amount of work that is required to be done. Calculation of pole strengths and ground clearances are completed and the results used to assist with renew or leave decisions. Load flows and fault level models are used as appropriate to assist with decision making.

The data gathered during inspections includes:

- The condition of overhead line hardware.
- Line clearances.
- Pole conditions.
- Pole type.
- Span lengths by direct measurement.
- Hardware attached including details of fittings.
- GPS position.
- Two or three photographs per pole/span.
- Pole test data using Deuar technology (when appropriate).
- Estimated age.
- Estimated life remaining.
- Labelling.
- Earth test results as appropriate.

Once this information is available, a detailed review of the asset condition, and what needs to be done to ensure it will last for another 15 years, is carried out.

In addition to the 15 year detailed condition and fit for purpose inspection, TLC carries out a three yearly hazard and vegetation inspection. This inspection is less detailed and the focus is on obvious vegetation and line hazard issues. Where possible this inspection is done from a helicopter to minimise costs. The cost of patrolling in a helicopter is $40 to $50 per km. Ground patrols cost 3 to 4 times this amount in the rugged rural areas of the TLC network.

Data gathered during three yearly inspections includes GPS locations, descriptions and photographs of problem areas. This data is loaded into the BASIX database and appropriate works orders are raised. Detailed specifications are prepared for many jobs.

Vegetation problems are reconciled with previous cut information and notices issued in compliance with the 2003 Tree Regulations. An administrator oversees this process.

The GIS database also contains information on line types and locations. Further information on line electrical characteristics is kept in the system analysis package (ETAP). The ETAP model includes load flow, fault current, circuit breaker sequencing, distributed generation, harmonic and arc flash modelling capability.

Hard copies of original construction drawings, inspection sheets and system single line diagrams are also referenced for further information as necessary when inspection, maintenance and renewal work is being carried out.

2.7.6.2 Unplanned Work

There are two principal drivers for unplanned renewal of overhead lines. These are faults and reported information of performance hazard issues.

Faults that cause a line to trip and stay tripped are fixed by faults staff. Advice on how to go about repairs is often sought from the Asset and Engineering group, particularly by field staff, for larger faults. This usually involves lines inspectors or technical staff going to site and specifying repair requirements. Works orders against the particular assets are then issued for these repairs.

About 80% of faults however are more intermittent in nature and, because of the rugged country, a more controlled approach to finding the problems often needs to be taken. After an initial check by faults staff, a line inspector will be dispatched to complete a detailed line fault inspection. Tools such as a discharge detector are often used. Technical staff will visit the upstream circuit breaker and download any fault history electronic records to ascertain the type of fault, and the fault current levels flowing into it. Modelling using the network analysis program to determine the fault location based on the fault currents may also be undertaken.

Often a helicopter inspection will also be completed to hasten progress as compared to ground based patrols. Once problems are found, plans and specifications are prepared and forwarded to the field staff. The level of detail in plans and instructions is vital for controlling the quality and consistency of repairs. The Asset and Engineering group establishes and follows up landowner entry permission. Engineering staff may also follow up with further technical studies and protection reviews.

Reports of problems are received from customers, staff and contractors. As soon as the Asset and Engineering group or control room becomes aware of a reported problem, an emergent work form is completed. This form becomes the tracking record of the problem. A lines inspector is then dispatched to investigate the problem further and complete the necessary designs, specifications and landowner arrangements. This work includes an understanding of the problem and overview of the line security issues in the area.

Once this work is done, the requirements are brought back and the package (inclusive of any labels, switch numbers, special safety requirements and suggested scope of outages) is forwarded to the field staff. The asset system tracks dates and jobs issued. On completion, a lines inspector is dispatched to audit the completed work against the design and work specifications. Board approval is needed for larger jobs via a variation to the Annual Plan.

The integration of the outage reporting, financial and customer systems are assisting with improved tracking of individual and lower level faults. Improved information is allowing better reconciliation of blown transformer fuses to individual ICPs for both revenue and SMS reasons.

This is important given TLC's capacity and dedicated asset components of charging. It is also important that faults on privately owned lines are tracked, as they often indicate a hazard. Customers may decide to minimise capacity and dedicated asset charges by having smaller transformers. Regular fuse blowing is recorded and billed to customers. Customers may choose to upgrade their transformer by sourcing a bigger one themselves or paying increased capacity/dedicated asset charges as opposed to paying fuse repair costs.

TLC keeps all historic line drawings as a backup information reference.

2.7.7 Ground Mounted Transformers: Routine Asset Inspections and Network Maintenance

2.7.7.1 Planned Work and Information: Ground Mounted Transformers

Ground mounted transformers are inspected on a five yearly cycle and major maintenance is scheduled every 15 years. There are a large number that have been identified as having hazards. Renewal of hazardous installations is included in the renewal programme and detailed in the long-term plan. Maintenance to reduce hazards has been included in the maintenance programmes. This mostly involves taping and covering exposed bushings etc. This is also included in the long-term maintenance plan. The inspection dates, hazards, repairs and other notes are recorded and this data is stored in the BASIX system. It is also available for use by the SMS.

The ground mounted equipment site information including type, capacity, current loading and condition is recorded and used to control the maintenance cycle. Most ground mounted transformer sites are also fitted with Maximum Demand Indicators (MDIs). Records are kept of these loadings and Maximum Demand (MD) loading data is being used to monitor connected loads.

Data, in addition to type, capacity and condition, includes full details on the types of locks and other fasteners etc. that secure the units from unauthorised access. This detailed information is stored in the BASIX system. Each site is photographed during the five yearly inspections. These photographs are currently accessed from the BASIX system and will be linked to the GIS system in the future. Further integration with SMS information is also being developed.

High-level data including site number and connected installations are stored in both the BASIX and customer billing systems. The BASIX system receives regular updates form the billing system on connected customers.

Original paper drawings, single line diagrams, GIS data, and photographs are all used as necessary during the management of routine asset inspection and network maintenance. The five and 15 year inspection and maintenance cycles are currently being managed by the BASIX system.

The BASIX system includes all data associated with outage calculations and the asset values associated with ground mounted transformers.

2.7.7.2 Unplanned Work: Ground Mounted Transformers

Feedback from customers, staff and other triggers such as faults cause the need to carry out unplanned work from time to time on ground mounted substations. The needs are identified and the repair requirements are specified to the level that is needed to ensure staff can carry out repairs in an efficient and effective manner.

Works and all information necessary to complete the repairs are recorded in the BASIX system.

2.7.8 Zone Substations

There are a number of systems in place to manage various aspects associated with zone substations.

These systems include the following.

2.7.8.1 Zone Substation Transformers: Planned

The zone substation transformers are maintained mostly on the basis of time, condition and duty cycles. A key driver for planned transformer maintenance are the oil test results for the main tank and tap changer.

The records kept as part of these tests include:

- Main transformer and tap changer type.
- All oil test results and consultants' notes on the assessment of transformer condition.
- Results of further tests, such as insulation loss angle.

Once completed, the test results are stored in BASIX against each individual zone substation transformer.

Maintenance including oil and transformer refurbishment is completed based on this data. As works orders are raised, more of the associated data are being entered into the BASIX system.

The cycle for oil tests is detailed in the lifecycle section of the Plan.

The normal condition and duty cycle issues are also taken into consideration when planning transformer maintenance. Examples of the issues that are considered include leaks, paint condition and the work that has been done in the past.

The BASIX system currently includes data for calculating outages and asset values associated with zone substation transformers.

2.7.8.2 Zone Substation Transformers: Unplanned

The unplanned work is normally caused by an unexpected event such as a fault of some type. When these occur the solution options are evaluated and the best for each particular circumstance is selected. Appropriate designs and instructions are prepared and works orders are issued to the appropriate organisations. All related information is stored in the BASIX system against the assets.

2.7.8.3 Protection and Switchgear: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Protection and switchgear records detail manufacturer's information, settings and maintenance. Generally this information is stored in paper-based folders. Protection setting data are also being recorded in network analysis software (ETAP). Duplicate copies are stored at both onsite and offsite locations.

Maintenance of this equipment including oil and contact maintenance, relay testing and other work is based on a 15 year cycle or need to maintain sooner basis. Works orders are raised and data updated in the BASIX system.

Protection valuation data and outage calculations are currently done in the BASIX system. Protection setting data are also being put into network analysis software (ETAP) to simulate circuit breaker, recloser and fuse operation under fault conditions. Electronic files associated with protection equipment are stored in at least two separate areas on the general computer system and separate mass storage devices.

Where equipment includes electronic software driven relays and other equipment, memory buffers are downloaded annually and settings are reconciled with records and network models. Similar checks and reconciliation are completed when it is suspected that equipment is not operating correctly.

2.7.8.4 Overall Zone Substation Related Processes for Managing Routine Asset Inspections and Network Maintenance

Planned and unplanned work (maintenance, renewal and capital) is controlled by the BASIX system. Asset and maintenance data on zone substations are stored in the BASIX system.

Several filing systems are used to store all other zone substation drawings and information. Two monthly inspections identify unplanned work and works orders are generated to rectify the problems found.

As stated in each of the component sections, the BASIX system contains the valuation and outage calculation data. The data are arranged in hierarchical segment sections.

The long-term inspection and maintenance forecasts, expenditure and plans are listed in the long-term network maintenance master plan.

2.7.9 Low Voltage Overhead Systems: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Historically very little data have been available on low voltage overhead systems, particularly in the rural villages. Steps are being taken to gather data as part of the 15 year line renewal programme (as explained in previous sections) and as a special project. The special project involves using more skilled labour to trace out the circuits and correctly record assets.

This data are entered in the BASIX system. In addition to data capture, the more complex low voltage arrangements have drawings and single line diagrams completed. Drawings are referenced via a drawing database.

The data in the BASIX system are used for valuations and works orders are issued against the assets. The geographical locations of low voltage systems are held in the GIS database.

The long-term inspection and renewal plan for low voltage systems is detailed in the overall long term renewal plan. The actual work flows and processes are the same as those described in the earlier overhead line system for both planned and unplanned activities.

Planned activities (excluding service boxes, which are discussed later) are generally completed on a 15 yearly inspection and renewal cycle.

Hazard and Vegetation patrols are completed on an 18-monthly cycle in dense urban areas and 3 yearly in the less dense areas. Issues identified are recorded and managed via the BASIX system. The 15 yearly inspection is considerably more detailed than the shorter term patrols and looks at overall issues that include tasks such as earth testing and the like.

Completed works are audited against quality, hazard control and work specifications. Unplanned events are focused on restoring supply and repairing the assets in a like-for-like manner. Works orders and instructions are created and all details of what took place and the costs involved are stored in the BASIX system.

2.7.10 Distribution Transformers: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Distribution transformers are linked to sites by their serial number and sites are linked to ICPs within the BASIX system.

The condition of distribution transformers is assessed:

- When customers request increased capacity or new connections.
- As part of the 15 year line renewal programme.
- When identified by faults or as part of emergent or planned project works.

A transformer serial number provides a record of the locations and other maintenance details of the transformer. The site number is the key linking number for data systems. Maintenance details such as earth tests are recorded against the site number. In addition, the site number links customers for billing and outage reporting purposes. Site numbers are linked to assets as part of the connectivity model in the BASIX system.

The distribution transformer data are complete in the BASIX system. All maintenance and inspection tasks are raised against the assets. The overall inspection, maintenance and renewal is controlled by the maintenance and capital long term plans.

Planned works are completed as part of the 15 yearly and hazard control programs in these plans. Unplanned works are completed as required to maintain supply in a secure and hazard controlled manner. The actual criteria applied to renew or replace are discussed in the maintenance section of this Plan. Historically distribution voltage tapping and phasing data have not been stored. Moving forward, systems are to be developed to include this functionality.

2.7.11 Other Equipment: Related Processes for Maintaining Routine Asset Inspections and Network Maintenance

Other field-based equipment has an equipment number that is attached to a site. The BASIX system allows maintenance to be controlled. Batteries and reclosers are examples of this equipment. The overall inspection, maintenance and renewal is controlled by the maintenance and capital long term plans.

2.7.12 SCADA and Communication Equipment: Related Processes for Maintaining Routine Asset Inspections and Network Maintenance

SCADA and communication equipment is managed by two external specialists who recommend renewal/development activities. The list of equipment is kept updated and has been transferred to the BASIX system.

TLC technical staff work closely with the external specialists to make sure there are long-term plans for renewal and maintenance of the SCADA and communication equipment. These plans are included in the maintenance and capital long term plans.

Works orders and specifications are prepared for all works and, on receipt of invoices, works are verified and recorded against the specific assets.

2.7.13 Vegetation Management: Related Processes for Managing Asset Inspections and Network Maintenance

The initial parts of the tree programme embarked on in 2003 focused on establishing a plan with the objective of improving reliability.

The focus shifted in 2007/08 and systems were set up to manage the second cut process in compliance with the Electricity (Hazards from Trees) Regulations 2003 (subsequently referred to as the 2003 Tree Regulations). Systems were tested and modified to get a simple but effective method that complies with the regulatory requirements. The system that was found to work best is a three yearly inspection of rural areas via helicopter with ground based 12 to 18 monthly patrols of the 24 villages and towns and 33 kV lines in the network. These patrols also identify other line hazards. Approximately 33% of the network is flown annually in a helicopter.

Problem areas are photographed and GPS positions recorded. A helicopter internet connected GPS device is used to identify locations accurately. The location and problem data are sorted after flights and various actions taken depending on the problems found.

Good records of where trees have been cut, landowner details and agreements reached, costs, number of trees and dates, types of trees etc. have been kept for many years. These data have been taken and additional fields added to manage this in compliance with the 2003 Tree Regulations.

The data associated with tree management are stored and linked to other asset records in the BASIX system. The vegetation work is carried out by one primary contractor and about five other smaller operators. TLC has no ownership stake in these contractors. Orders are raised for all works (both planned and unplanned) and activities are audited to ensure quality and hazard control meets expectations.

TLC has to control the hazard implications of customers receiving their second trim notices and then attempting the work themselves to save costs. Vegetation notices and staff are alerting customers of the risks of cutting trees around power lines with each communication.

A detailed model of the tree programme has been put together and used to predict future needs and expenditure based on several scenarios and assumptions. This model was used to develop a strategy that will increase focus on maintaining the areas that have been cut previously. The tree model feeds into the long-term maintenance and is co-ordinated with capital works projects.

2.7.14 Pillar Boxes: Related Processes for Managing Asset Inspections

In undergrounded urban areas pillar boxes are often damaged by vehicles, and when damaged can potentially be accessed by children. As a consequence, the boxes were initially inspected in 2003/04 and urgent repairs completed. Pillar boxes are now being inspected on a five yearly cycle, numbered, the position confirmed by GPS and details recorded in the database. As each new subdivision is connected, all boxes are audited for security, numbered and details recorded. The BASIX system has been developed to hold service box data including age, type, condition and other details. These data are limited to the SMS.

The long-term renewal and maintenance plans include allowances for planned renewals and unplanned renewals/repairs. Further details on these are included in subsequent sections.

All works are managed by the works order system and completed works are audited for quality, hazard control and SMS compliance.

2.7.15 Processes for Planning and Implementation of Network Development Projects

As outlined previously, TLC has formulated a network development plan out until 2027. This Plan is integrated with the renewal and maintenance plans. Inputs include the load growth predictions discussed in later sections of this Asset Management Plan. These were developed from load and other relevant data. Projections of loading on individual assets were developed using the ETAP network analysis package.

The results of this analysis are also reconciled to demands on the various network segments that customers are charged, i.e. measured system loadings are reconciled to reports coming from the billing system to ensure that the sum of customer demand charges are within expectations.

The long-term development plan washes down into the Annual Plans. It is reviewed and, from time to time, has to be varied. Most variations are triggered by customer demands. The constraints, development options, the year works are planned for and estimated costs are included in the development section of this AMP.

2.7.16 Customer Driven and System Growth: Planning and implementation

There are various processes for customer driven development based around the size of customer needs. Once a customer need is established, concept options are developed. Needs for major customers are normally established by site visits and discussions. Tools such as load flow studies and fault analysis are used to develop the concepts. The network details, down to distribution transformer level, are stored and regularly updated on the ETAP network analysis program to assist with the process.

Once 'what will work' options are determined, high-level costs are estimated and the advantages and disadvantages of each option are debated. This will normally include customer consultation so that the benefits of each option can be accurately assessed by the customer. These discussions are used to determine a number of things, including the amount of future proofing a developer or industrial customer wants to fund.

Customers are also encouraged to consider alternative supply options if these will fulfil their lifestyle or enterprise expectations. Customers normally do not have a technical background and as a consequence have little understanding or sometimes an incorrect perception of what alternatives are available. TLC staff keep up to date with where the various technologies are at including the latest costs and performances. Information given to customers is based on these facts.

Most of the customer development requirements involve modifying or extending the network. Customers may choose to build their own private lines to the network point of connection. (The point of connection is often different from the point of supply; point of supply is where a line crosses into the customer's property, except as otherwise specified in the Electricity Act.) They may also nominate the capacity of their connection and customer ownership options for dedicated assets such as transformers, i.e. either they own them or TLC owns them and they pay for this as part of their account. The implications of ownership such as compliance with the Electricity (Safety) Regulations 2010 is pointed out when this option is chosen.

Where the network presently owned by TLC needs upgrading, discussions are held with the customer as to funding options. These are usually either an upfront payment or an appropriate dedicated asset charge when revenues will not fund the development. These funding requirements are either individually calculated or, for smaller connections, generically determined. All charges are based on Commerce Commission criterion and determined using discounted cash flow type modelling.

The long-term plan includes expected levels of customer development needs and a few known customer projects. Also included are core network strengthening projects necessary due to the cumulative effects of customer development. The costs of these plans are included in each year's Annual Plan and the forward projections and projects that we have details on are included in the overall master plan.

New customer connections trigger a whole number of processes that include:

- Asset record updates.
- Electricity market registry.
- TLC charges and billing system.
- Single line diagram and control room maps.
- GIS system.
- Connection costs.
- Equipment records.
- Land access information.
- Metering and load control data.

Where specific customer needs are unknown, estimates have been included in the forward plans based on the expected times developments will occur.

2.7.17 New Connections: Distributed Generation: Planning and Implementation

The processes detailed in the Electricity (Distributed Generation) 2009 Regulations are followed. Experience has shown that investors tend to not want to employ the engineering expertise they need to complete applications to a level where they can be approved.

TLC does not employ contingency engineering or legal resources and, as a consequence, additional resources must be employed to handle larger applications. These resources have to be funded by the generation investor.

There is a lot of variation in the needs for processing distributed generation applications. Small applications can connect without any significant effects. Large applications quickly become considerably more complex, especially on a remote rural network.

The current distributed generation regulations were not designed for the realities of connecting complex installations. Further discussion on these issues is included in later sections. At presently hardcopy and electronic filing systems are used to manage distributed generation applications in compliance with the regulations.

A number of the applications TLC currently has underway have triggered complex legal processes controlled by the Electricity Authority.

2.7.18 Other Projects: Planning and Implementation

Security, hazards and reliability projects feed from a list of long term development plans, which are detailed in the later sections of this document. These are reviewed annually and, if necessary, varied. The amount of variation is minimised as far as possible. The latest customer needs, security, SMS, worker hazards, reliability information and performance criteria are used as the foundation for any variation from the long-term plan.

2.7.19 Processes for All Projects

While the planning and control depends on the specific project, the same underlying steps are applied to all projects. These steps are:

- Identifying the needs/justification.
- Determining the options.
- Concept design to produce pricing estimates.
- Funding/revenue agreements.
- Detailed design.
- Approvals.
- Construction.
- Auditing against Quality, Specifications, SMS and Worker Hazard Control.
- Commissioning.
- Administration and data control.
- Systems to receive on-going revenue.

Many of these underlying steps are very minor for small projects and significant for larger ones.

The detailed justification for each network project is submitted to Directors for approval in the Annual Plan. Variations are also submitted. Once approved, detailed designs, specifications and landowner arrangements are completed as part of the project costs. Once finalised, these plans are forwarded to contractors for construction. On completion, an audit is undertaken to ensure compliance with specifications. Engineering resources are made available to address any technical issues associated with construction and commissioning.

The works order system is used to compare actual costs of projects with estimates. Major projects are ring fenced and compared against high-level concepts that are initially developed to analyse options. A system is currently being set-up to compare construction costs with national data prepared by SKM and PriceWaterhouseCoopers.

More detail is developed and compared against criteria to justify the project on financial, worker hazards, SMS reliability, capacity or system security or combinations of each of these. The proposals are written up and approval sought from Directors to proceed. About 90% of these are included in the Annual Plan and budget. The remaining 10% are submitted during the year when an emergent need occurs. Examples of emergent needs include unanticipated customer growth projects and major emergent repairs after faults. Once approval is obtained, detailed plans, specifications and other details are finalised. A job package is prepared and forwarded to the Service Provider.

The Service Provider provides a final cost and this is reconciled against the estimates. Approvals are sought for any variations against the estimates that were part of the planning process. Work orders are raised against assets in the BASIX system for all works. Actual costs are reconciled when these become available from the financial system. Going forward, these will be reconciled to market rates and/or national survey prices.

2.7.20 Processes for Measuring Network Performance for Disclosure Purposes

Preparing disclosure reports for performance measuring and evaluation has often been a stressful process. To minimise this staff pressure, and maximise organisational efficiency, TLC has been developing processes to increase the automation of reporting. This also has other advantages including minimisation of errors, provides consistent information, is backed up by documented specifications and reduces the risk of a single staff member leaving with key intellectual knowledge that is difficult to replace.

Good progress has been made with this, especially with the BASIX system over recent years and continuous development/improvement is taking place.

2.7.20.1 Financial Performance

The policy is to review financial performance of all levels of network operations, including income and costs on a monthly basis. The monthly reports are reconciled against the Annual Plan. Variations over 10% have to be individually reported to Directors along with explanations for these variations.

Annual financial disclosure information comes from the financial system. The financial system includes the normal inputs of debtors, creditors, payroll etc. The system is progressively being developed to produce outputs aligned to disclosure regulatory requirements with minimal spread sheet manipulation.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2008 that the financial system provides information for include:

- Report FS1: Regulatory Profit Statement: Schedule 2
  (All from the financial system except line 50, which comes out of the BASIX Regulatory Valuation Calculator)
- Report FS2: Regulatory Asset and Financing Statement: Schedule 4
  (Lines 8 to 23 are reconciled between the financial system and the regulatory asset value calculator).
- Report FS3: Regulatory Tax Allowance Calculation.
  (All from the financial system.)
- Report AVI: Annual Regulatory Valuation Roll-Forward
- Report: Schedule 5
  (Lines 36 to 42 are produced by the financial system. The remainder (lines 12 to 33) come from the BASIX regulatory value calculator).
- Report MP2: Performance Measures: Schedule 10
  (The financial system produces lines 10, 15, 20, 25, from data reconciled between the financial and BASIX regulatory calculator. Lines 11, 16, 21, 26, 30 and 31 come from the BASIX regulatory calculator).

2.7.20.2 Customer Information

The billing system Talgentra is used to produce customer information for disclosure performance information. The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2008 that the billing system produces information for is:

- Report MP3: Price and Quality Measures: Schedule 11
  (Line 76 is from the billing system (reconciled to financial system). Lines 14 to 67 and 78 come from the BASIX system).

2.7.20.3 Valuation

A valuation calculator has been set up in the BASIX system to produce valuation information in line with disclosure requirements. In addition, this system uses the asset data to produce accounting valuations. The valuation calculation is complex and uses data from multiple fields to produce the various valuations.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2008 that the BASIX valuation produces data for include:

- Report AV2: Regulatory Valuation Disclosure by Asset Class (for system fixed assets) Schedule 6
- Report AV3: System Fixed Assets Replacement Cost Roll-Forward Report: Schedule 7
- Report AV4: Business Merger, Acquisition and Sale – Asset Base Disclosure: Schedule 8. (Not applicable to TLC at this time.)

2.7.20.4 Network Information

The BASIX system, SCADA logs, Billing System, Network Analysis and Transpower Accounts are used to complete the network data section of the Electricity Distribution (Information Disclosure) Requirements 2008 network information schedules.

These include:

- Report MP1: Network Information: Schedule 9

Specifically:

- Circuit length by Operating Line Voltage (at year end): BASIX
- Overhead Circuit Length by Terrain: BASIX
- Transformer Capacity: BASIX
- Systems Fixed Assets age: BASIX

Electricity Demand and Volumes:

- *System Demands:* SCADA Logs, embedded generation data and Transpower demand data.
- *Large Customers:* Metering Data.
- *Electricity Carried:* Transpower and Metering Data.
- *Network Losses:* Network Analysis Software and Reconciliation Manager Reports/Data
- *Numbers of Connection Points:* Basix
- *Intensity of Services:* Self filling

2.7.20.5 Expenditure Forecasts and Reconciliation

The expenditure forecasts are developed in BASIX and broken down into individual jobs and items. This planned and forecast expenditure is allocated to disclosure categories. Actual expenditure data is manually entered from the financial system.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2008 that the job planning system produces information for includes:

- Report AMI: Expenditure Forecasts and Reconciliation: Schedule 12.

2.7.20.6 Reliability Reporting System

Reliability reporting is via the BASIX system. Fault information is entered from daily reporting sheets, which in turn are completed from a variety of sources including SCADA, sentries, the telephone database and control room logs. The data are entered, run and checked every few days. The results are reconciled to control room data. Monthly performance reports are generated and reviewed at both management and Director level. Customer numbers are updated regularly from the billing database.

Equipment failures in the various sections of the network and the SAIDI/SAIFI effects of these are monitored closely. Reports are set up in the system to produce the regulatory and internal performance data, including Commerce Commission Decision 685 reports.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2008 that the reliability reports (BASIX) system provides information for include:

- Report MP3: Price and Quality Measures: Schedule 11.

2.7.21 Processes for Measuring Other Performances

2.7.21.1 Contractor Performance

Contractor work practices and quality are monitored for both network and private line connections. Contractors are not paid until they have completed works to specifications.

If construction audits reveal work standards are not meeting industry hazard control expectations, contractors' network access is cancelled. The contractor then has to submit details of how systems are going to be put in place to overcome these deficiencies before they are reinstated. Rework levels are monitored, as is SMS compliance.

2.7.21.2 Customer Service Levels

The BASIX system is used to report on the customer service levels as described in Section 4 and reported in Section 8. These include time to restore supply and maximum number of shutdowns.

Software calculators and reports have been set up to produce monthly and annual reporting on these performance indicators. Considerable effort is put into ensuring that the input data are accurate and timely so that these reports are correct.

The telephone system provides reports on the number of calls and unanswered calls.

2.7.21.3 Customer Consultation

Customer Service Representatives record the number of customer clinics and focus group meetings that they are involved in annually. The number of customers attending and the number of presentations made by the Customer Services Manager explaining TLC's pricing methodology and advice on reducing kW load for individual customers are recorded.

2.7.21.4 Asset Performance Targets

The BASIX system is used to measure voltage complaints and system component failures. The network analysis and Annual Plan is used to determine and measure the number of legacy network voltage issues addressed.

Harmonic levels are measured using a high voltage clip-on sensor link meter. Results are currently recorded by the Design Engineer.

2.7.21.5 Asset Efficiency Targets

Network technical losses are calculated using models that include the effects of generation. The data supplied by retailers on non-technical losses has been shown over the years to have very limited accuracy. To get around this problem TLC pays a Reconciliation Manager to produce data that show the energy sold by balancing areas (as defined in Electricity Governance Rules) and grid exits. TLC takes these data and subtracts them from the technical losses to determine non-technical losses.

Network supply point power factor is measured from the national data set available from the Electricity Authority.

2.7.21.6 Asset Effectiveness Target

Network incidents/accidents are measured from the incident reports submitted to the HR section. The number of hazards removed from the network each year is measured when actual works are reconciled with forecasts.

The ratio of billed kVA to the sum of the kVA of distribution transformers is determined from BASIX and the billing data boxes by running sequel server reports.

2.7.21.7 Lines Business Activity Efficiency Targets

Most of the other asset reports are based on disclosure information. The sources of disclosure information are discussed previously.

Most of the disclosure data comes from the BASIX and financial systems. An objective of our system development is to produce these outputs directly from system reports without any additional spread sheet calculation, maximising accuracy by minimising the risk of errors. We are close to achieving this.

In summary, the financial based targets are reported from the Navision (financial) system, customer numbers from the billing (Talgentra) system and asset information, including reliability, from the EMS BASIX system.

2.8 Future Asset System Integration and Advanced Network Vision

The technology available for more advanced networks is developing with increasing speed. There are many aspects to this but a central component to most schemes is the need to control demand in customers' installations.

TLC's demand based billing uses the tools currently available to do this. As time goes on and meters with better technology built into them become available the pricing strategies will be further refined. For example large customers are currently charged on kVA demand, smaller customers kW demand. When single phase and small three phase meters are available to give kVA demand at smaller sizes, TLC will move to charging on kVA. (This encourages customers to improve power factor.) Similarly, meters in the future may include elements for measuring power quality and it is likely that customers who pollute will face the costs associated with this. It is probable that communication between meters and customers will also significantly improve in the future.

Running in parallel with this there are significant advances being made with distribution equipment technology. For example, protection and system automation equipment has advanced significantly over the last few years. Controlling and using all of this equipment is a key consideration for data and information systems looking forward.

TLC has given considerable thought to the 'future vision' when selecting and designing the way its data and information tools are selected and developed as part of its continuous improvement approach. The owners of packages such as ETAP (TLC's network analysis program) have developed some comprehensive network automation capability.

Similarly, the present SCADA, billing and asset management packages will all have a place in the asset management processes for advanced network schemes throughout the planning period.

A major focus over the next period is to develop a plan to bring these technologies together in an innovative way to benefit customers.

Section 3

3. ASSETS COVERED

3.1 A High Level Description of the Distribution Area

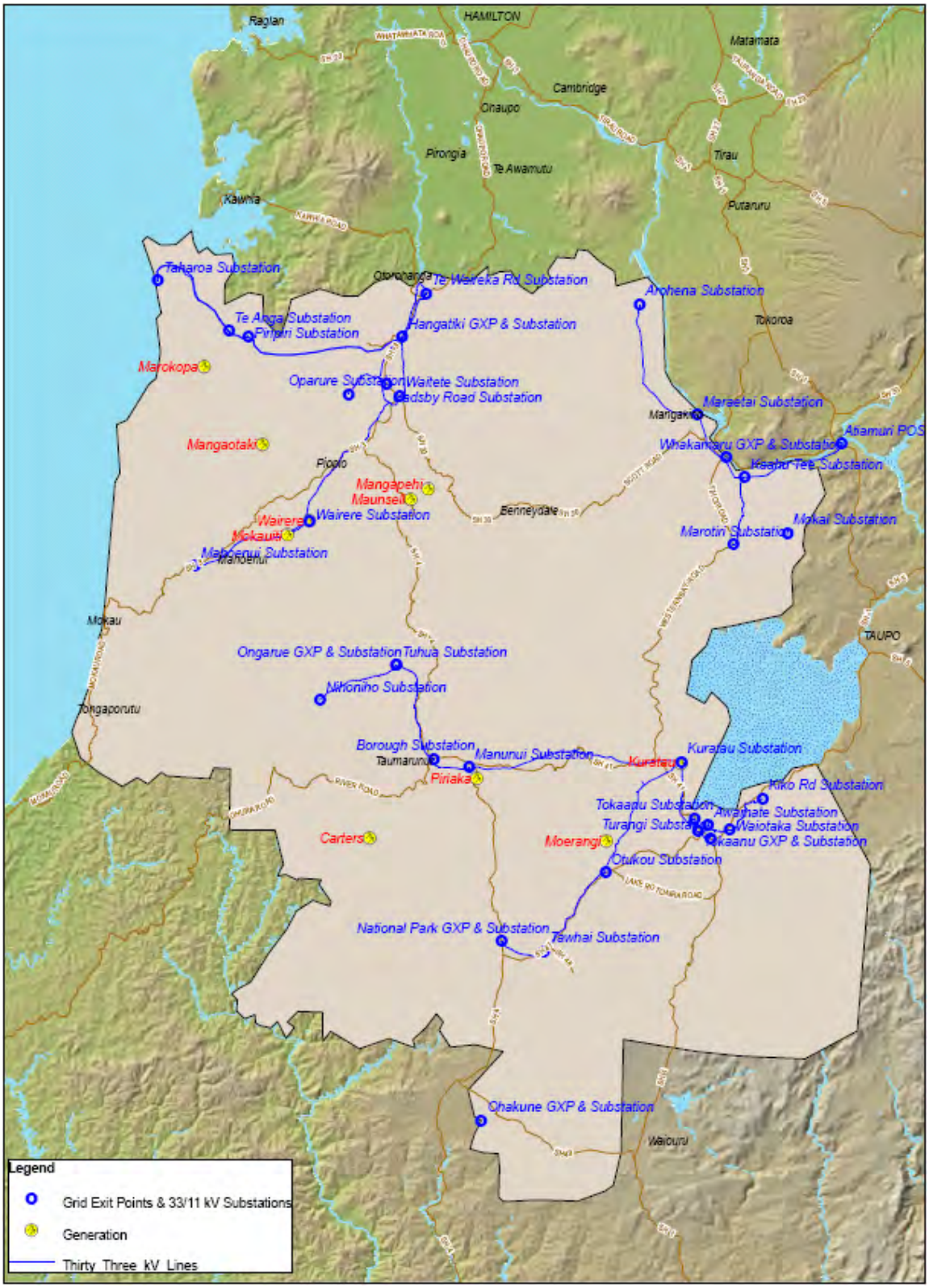


FIGURE 3.1: DISTRIBUTION AREA COVERED BY TLC NETWORK

3.1.1 Distribution Areas Covered

Figure 3.1 illustrates the distribution area covered by The Lines Company network. Also illustrated are 33 kV sub-transmission lines, Transpower grid exit connections, and major generator supply points and embedded generators. The distributed generators are indicated by the arrows in a yellow circle symbol.

The north-western part of the area starts on the south side of the Kawhia harbour. The south-western corner is Mt Messenger. From this point the network area to the east includes Mt Ruapehu and the two large ski fields (Whakapapa and Turoa), Ohakune and most of the area around Lake Taupo excluding Kinloch and the town of Taupo. The area then follows the south bank of the Waikato River to Arohena then west back to the southern side of the Kawhia harbour. The area covers 13,700 km2.

The asset boundaries are downstream of the Transpower grid exit points, as defined in Transpower standards, through to customers' points of connections as defined in TLC's Terms and Conditions of Supply. (Note: The 'Point of Connection' can be different to the 'Point of Supply' as defined in various sections of legislation. The point of demarcation between customers and network assets can be complex and difficult to define in legislation. Much of this difficulty is because the various amendments to Acts and Regulations over the last 40 years have not been consistent on this issue.

In cases where supply is taken from more complex arrangements such as the Whakamaru area, the demarcation point is that defined in the contractual documents, or at the boundaries of the assets owned by TLC. The asset boundary for distributed generators is the 'Point of Connection' as detailed in TLC's Terms and Conditions of Supply.

3.1.2 Network Characteristics

Some of the asset layouts within the TLC network are unique, while others are typical of New Zealand network companies.

The unique configurations include:

- Few lines on roadsides. Lines tend to go from hill to hill in predominately rugged terrain.
- Large number of Single Wire Earth Return (SWER) systems (60 plus).
- Significant area is supplied directly from major Waikato generation plants bypassing Transpower grid exit points (GXPs). (Note: A new milk plant at Mokai means that this arrangement has become a little more unique and includes an inter-connectable embedded network supplied directly from the Mokai geothermal plant.)
- Large number of distributed hydro generators.
- Sparsely populated rural network with no major urban centres.
- Long lengths of 33 kV network connecting distributed generation and zone substations.
- Long lengths of privately owned 11 kV lines often in remote rugged country.
- Apart from the special 11 kV cables on Mount Ruapehu, there are relatively few 11 kV cables in the network.
- Generally old network.
- Many of the lines have low mechanical strength and close conductor spacing with long spans.

The typical layout is grid exit connection being at 33 kV and this is passed onto zone substations. 11 kV feeders radiate out from these substations to towns, settlements and rural customers where supply is transformed to 400/230 V.

Company policy is to regard any line that supplies a property owned by a single entity as private regardless of voltage. The private lines start at the Point of Connection to the network and then travel to individual properties. The 'Point of Connection' may or may not be the 'Point of Supply'. (The 'Point of Supply' is defined in legislation and, in most cases, is the point where a line crosses the boundary to a property.) If these lines were included in the assets owned by TLC, the likely line length increase would be a further 20% or approximately 800km.

These private lines can be non-compliant with present day codes and, from time to time, cause faults that affect other customers. The Electricity (Safety) Regulations 2010 have also imposed further liabilities on the owners of these lines in terms of compliance.

The Waikato River connection arrangement for part of the TLC network means this section of the network is not subjected directly to Transpower connection and interconnection charges. However, other asset and generator costs replace a number of these charges.

3.1.3 Large Customers that have a significant impact on network operations and management priorities

The large customers that have a significant impact on network operations and management priorities fall into two groups, customers that draw load from the network and those that generate into the network.

3.1.3.1 Large load taking customers who have a significant impact on network operations

a.	**Business:**	**Iron sands extraction** Iron sands processing and ship loading.
	Location:	Taharoa
	Dedicated Assets:	Approximately 100km of heavy 33 kV line, one zone substation and two Transpower grid exit circuit breakers.
	Impact on TLC Network:	The plant has a steady mining load of about 3 MVA, that increases to 8 - 10 MVA during 9 to 10 annual ship loadings over a three day period. It is during these periods that the Hangatiki grid exit system peak loads occur. The zone substation at Taharoa has been constructed on a west coast iron sand beach. The maintenance and renewal requirements for the site are high. The amount of dedicated asset, the income received from this, the size of peaks and the amount of maintenance required to ensure assets are reliable has a significant impact on network operations. The plant has an impact on system losses. The customers' commitment to increase the size of the bulk carrier ship means that there will be a re-investment into the site over the next two to three years. The mining load will increase to 7 to 7.5 MVA and with the ship pumping load, to a total site load of 14 to 15 MVA.
b.	**Business:**	**Ski Fields** Operators of Whakapapa and Turoa Ski field chairlifts, ski field facilities and snow making
	Location:	Mt Ruapehu
	Dedicated Assets:	One Zone Substation. Approximately 25km of on-mountain cables, 40 ground-mounted transformers, 11 kV on-mountain switchgear, 4 regulators, and 5km of 11 kV lines.
	Impact on TLC Network:	An additional 6 MVA (approx.) of winter peak load is added to TLC network. The installations are in extreme, very sensitive environments that require constant maintenance and renewal work. The owner and operator of the ski field are progressively investing in development of the ski field.

c.	**Business:**	**Corrections Department**
	Location:	Hautu and Rangipo Prisons.
	Dedicated Assets:	Approximately 15km of 11 kV overhead lines. 33/11 kV modular zone substation.
	Impact on TLC Network:	Adds about 1 MVA of load to the Tokaanu grid exit point. The customer has requested and funds a higher level of reliability.
d.	**Business:**	**Limestone extraction and processing**
	Location:	Six plants at several locations surrounding Te Kuiti
	Dedicated Assets:	One 3 MVA 33/11 kV substation, 7km of 33 kV lines, approximately 15km of heavier 11 kV line, onsite distribution transformers and switchgear.
	Impact on TLC Network:	Have a combined load of about 8 MVA. Operating loads tend to be seasonal and dependent on orders. Connected plant consists of mainly large motors that tend to reduce network power factor. These loads add to autumn loads.
e.	**Business:**	**Meat Processors**
	Location:	Two plants on Te Kuiti urban boundary and a third plant at the end of two 40km long 11 kV feeders.
	Dedicated Assets:	Four regulators, distribution transformers and associated 11 kV switchgear. Approximately 5km of heavier overhead line.
	Impact on TLC Network:	Combined load of about 7 MVA. Plants on town boundaries are connected to 11 kV feeders. Reclosers are located on these feeders just beyond the plant Point of Connection. The object of these reclosers is to isolate the sections of rural line when faults occur beyond the plants. The plants are, however, sensitive to switching surges and discussions are underway to provide the plants with dedicated 33/11 kV zone substations to reduce voltage sag. The plant at the end of two long 11 kV feeders, needs three to four regulators to support voltage and adds to the operating complexity of these feeders. (Half the plant is supplied from one feeder and half from the other.) The plant location has an impact on system losses.
f.	**Business:**	**Timber Processors**
	Location:	Two plants on Te Kuiti urban boundary. One plant at Tangiwai. Several smaller plants at Taumarunui and Otorohanga.
	Dedicated Assets:	Local distribution transformers and switchgear. Approximately 5km of dedicated 11 kV line at Tangiwai.
	Impact on TLC Network:	Two Te Kuiti plants have a combined load of about 5 MVA. The plants are connected to the 11 kV network and are sensitive to feeder faults, auto recloses, and surges beyond the connection points.

g.	**Business**	**Energy Park: Milk Plant: Glasshouses: Reinjection Pumps**
	Location:	Mokai
	Dedicated Assets:	Local distribution transformers; fault reducing transformer; 3 11 kV metering units; approx. 3 km of heavy cable; 11 kV switchgear and ring mains; approx. 7 km of 11 kV overhead lines; reclosers; automated 11 kV switches and related RTU's.
	Impact on TLC Network	The energy park network is directly connected to the Tuaropaki Power 120 MW geothermal plant. The network interconnects with the TLC network and 2 way energy transfer is possible.

3.1.4 Generation Customers that have an impact on network operations

The connection of generation to networks quickly adds complexity.

Examples of the issues include:

- Islanding.
- Voltage fluctuations.
- Alters network voltage profiles.
- Frequency fluctuations.
- Auto-reclosing difficulty.
- Self-excitation.
- Protection.
- Current Flows: Positive, negative, zero sequence and fault currents.
- Resonance.
- Increased fault capacity.
- Losses.
- Commercial terms of connection.
- Power factor (Distribution network and grid exit).
- Energy reconciliation.
- Network stability.
- Other unusual effects.

Further details on these issues are discussed in later sections of this Plan.

The owners of distributed generation plants usually have little power system engineering expertise and have difficulty understanding the often complex technical issues. Frustration between the network and the generation investors can occur.

The following is a summary of the impact of the various generators' plants on the network operations and asset management priorities. More specific capacity details are included in later sections of this Plan.

a.	**Business:**	**Energy Retailer**
	Location:	Kuratau Piriaka Wairere Falls Mokauiti
	Dedicated Assets:	33 kV lines, two zone substations, 33 kV switching equipment, 11 kV lines, 11 kV switchgear.
	Impact on TLC Network:	This plant was originally owned by local power companies and split out at the time of the Bradford reforms. The plant and network are integrated and designed to be operated as one. Separation did create a reduction in operating and energy delivery efficiency. (Many of the plant controllers and much of TLC's voltage control equipment has been updated over recent years. This has meant that it is now possible to restore some of this efficiency by tuning the new equipment settings in conjunction with the use of TLC's network analysis programme.) These distributed generators have a significant effect in reducing grid power factor. The presences of the plants affect asset management and operational decisions. Each plant has the following summary implications:

Kuratau	Output is normally back through the network to the Ongarue grid exit point. This plant causes the grid exit to run backwards for long periods. The Kuratau generation connection arrangement and controller restricts auto-reclosing on some 33 kV lines. This has caused longer outage times. This input into the transmission grid causes Transpower charges at Ongarue to be proportioned between injection and off-take. In the present operational configuration, the Manunui to Kuratau 33 kV line is almost exclusively used for the transportation of this generation back towards the Ongarue grid exit point. The present generator controllers at Kuratau cause some unhealthy surges in combination with the investor owned Moerangi generation on rundown after a line tripping. The output is used to maintain network voltages during shutdowns of the Ongarue, National Park, and Tokaanu grid exits. The plant increases the network voltage at Taumarunui during some periods. Injection of the Kuratau generation into Ongarue adds to system losses as compared to the alternative Tokaanu. Kuratau generation does not tend to island except for the above-mentioned oscillations on rundown. At light load times the Kuratau controller's limited ability to absorb reactive power means the light load voltages can become excessive. (Some improvements to this have recently been made.) The plant reduces the Ongarue grid exit power factor.
Piriaka	The Piriaka site was the original supply point for Taumarunui. The output is used to maintain network voltages during shutdowns of the Ongarue, National Park, and Tokaanu grid exits. Over the last year improvements have been made to the plant controllers and protection by the owners. Previously the plant islanded and produced varying frequencies and voltages. These varying frequencies and voltages had the potential to destroy large numbers of customers' electronic appliances. The plant causes a reduction in the Ongarue grid exit power factor. The plant increases the network voltages during some periods.
Wairere Falls	This historic plant was originally built to supply the Piopio area. The plant will island, cause surges on rundown and restrict auto-reclosing. It can however be used to support the network. Preliminary discussions have been had with the plant owners to improve the controls at this plant site. The plant causes a reduction in the Hangatiki grid exit power factor.
Mokauiti	The connection is integrated into that of the Wairere Falls complex. The site has two induction machines that tend to not cause many adverse operational effects. The plant causes a reduction in the network and Hangatiki grid exit power factor. There are currently no operational capacitors providing additional power factor connection.

b.	**Business:**	**Subsidiary of TLC owned**
	Location:	Mangapehi
	Dedicated Assets:	Regulators, 11 kV lines, complex circuit breaker and regulator settings.
	Impact on TLC Network:	The 2 MW Mangapehi generation has caused a number of technical difficulties that have had to be solved since its initial connection to the network in 2002. The generation is 'run of the river' and there is growing industrial load in the area. When water is available, regulators have to be used in reverse to reduce generation output voltage. Other technical difficulties with this plant have included zero sequence current flow and resonance problems. In more recent times most of these problems have been understood. An innovative control scheme has been developed to co-ordinate the output of the generation and industrial load to improve power quality and energy efficiency in the area. The plant increases network voltages. The plant also causes a reduction in the Hangatiki grid exit power factor.
c.	**Business:**	**Investor owned**
	Location:	Marokopa
	Dedicated Assets:	11 kV line and 11 kV 200 kVA transformer.
	Impact on TLC Network:	The 2 induction machines totalling 200 kVA at the Marokopa site has the following impact on network operations and asset management: » Reduced network and Hangatiki grid exit power factor. » Makes the use of generator by-pass during planned work shutdowns more complex. » Has the potential for self-excitation on rundown.
d.	**Business:**	**Investor owned**
	Location:	Moerangi Station
	Dedicated Assets:	33 kV line, 33 kV/400 V 200 kVA transformer. Lightning arrestors and drop out fuses.
	Impact on TLC Network:	The 2-3 induction machines totalling about 150 kVA at the Moerangi site has the following impact on network operations and grid exit power factor: » Reduced network and Ongarue grid exit power factor. » Has caused network self-excitation and over voltages. » Interacts with the Kuratau KCE plant and some oscillations have occurred that have destroyed electronic equipment in the area.

e.	**Business:**	**Investor owned**
	Location:	Mangaotaki Valley
	Dedicated Assets:	Dropout fuses
	Impact on TLC Network:	Two 75 kW induction machines. The Mangaotaki site has the following impact on network operations and grid exit power factor: » Reduced Hangatiki grid exit power factor. » Makes use of generator by-pass during planned work shutdowns more complex. » Has the potential for self-excitation on rundown. » Uses up all available generation capacity on existing lines in the Mangaotaki Valley area.

3.1.5 Impact of Large Customers on Asset Management Priorities

All large customers have some impact on asset management needs. In TLC's case, there is on-going communication with each of these customers and the long-term asset plans the network has consider the expectations communicated by customers.

TLC recognises that large customers need to be competitive in their enterprises in both the national and international market places. As a consequence it is not possible to increase prices to this group of customers to subsidise the renewal of remote rural lines. Pricing to large customers has to be calculated on the actual cost of supply.

The customers are advised of any hazards observed with equipment around their plants. In most cases, the owners of the plants are responsible for the funding to eliminate or minimise these hazards. The asset management and network operational impacts caused by the presence of these large customers include:

3.1.5.1 Ski Field operators

The ski field operators co-ordinated a process to fund the cost difference between renewing the existing overhead line to the Whakapapa area and undergrounding the 7km of overhead line. This project was completed in 2008. Further development has taken place on the Turoa Ski Field with the installation of ski lifts, snowmaking, and network inter-connected generation.

Both ski fields had, and still have, some higher hazard related risk sites on the ski field. Over the last few years, about 18 have been addressed including the installation of significant amounts of appropriately rated switchgear. This Plan includes estimates for addressing most of the remaining hazards on both sites. The ski field operators are aware of the higher risk sites and the need for the hazard minimisation/elimination program. Reliability to the Ski Fields has improved as a by-product of removing hazardous equipment.

TLC is also working with ski field owners to minimise peak-based charges by operating on-field generation into the network. Alterations to the network over the last six years have been completed in a way that this can be accommodated. The ski field and related accommodation use affect National Park and Ohakune grid exit peak loads. These loads are included in asset management planning.

3.1.5.2 Meat and Limestone Processors, Te Kuiti

Owners of a number of these plants have concerns about voltage sags and reliability. These concerns are leading to a change in asset design approaches. Specifically, TLC is planning for smaller localised zone substations to fulfil these customers' needs.

A number of the plants have hazards associated with the transformer enclosures and switchgear they own. A number have proposals to eliminate/minimise these hazards. It appears that the current economic downturn is delaying improvements. The ways these changes will affect the network have been included in long-term forecasts and development plans.

The peak meat and lime processor loadings occur in late summer. The timing of these loadings is currently driving the loss of n-1 capacity at the Hangatiki grid exit. During the late summer when these peaks occur, the run of the river distributed generation has low output. Most of the energy that these plants consume through these periods has to be sourced from the national grid as opposed to the outputs of distributed generation.

3.1.5.3 Iron sand extraction

The current iron sand extraction process at Taharoa involves pumping product in undersea pipelines to about 3 km off shore onto large ships. Supply reliability is essential and work has been taking place to improve this.

The economic downturn stalled plans for reinvestment at the site. The site is in poor condition and an amount has been allowed for to eliminate/minimise hazards associated with the site. The need to eliminate/minimise hazards and other impacts of the Iron Sand's operation has been considered when developing Asset Management Plans. The plant has recently indicated that it is willing to fund reinvestment as a consequence of forward customer supply contracts.

3.1.5.4 Mokai Energy Park

The Tuaropaki Trust has created an industrial Energy Park on land they own adjacent to the 120 MW Tuaropaki geothermal plant. TLC has constructed a network that interconnects with other assets and supplies energy park customers. The TLC assets include a fault reducing transformer, metering, SCADA, cabling, overhead lines and switchgear. This equipment is used to supply a milk plant and glasshouse in the industrial complex. These loads cannot be back fed totally from the surrounding legacy network. Hire generators have to be used to support this load when the geothermal plant is not available. The fault levels are high and appropriately rated assets have to be used.

3.1.5.5 Distributed generation

Most sites connected to the TLC network have some issues and needs that require network engineering attention. However, currently, these issues have a lower priority for engineering time than other needs such as hazard elimination/minimisation.

Looking forward however it is planned to change this and tune the integration of these plants into the network to improve energy efficiency. This has become possible in recent times as outlined in the earlier part of this section, mostly due to improved network models becoming available.

Specifically, current examples of this are:

Mangapehi: The work to be completed includes the tuning of regulator, protection settings and adjustment of about 20 to 30 local transformer tap settings. A few days of engineering time is required using the analysis package to determine the most effective and efficient settings.

Kuratau: The work to be completed includes adjustment of controllers to stop voltage surges on rundown; working with owner to ensure plant can be auto-reclosed and renegotiating connection contracts and allocation of the costs of dedicated assets. The owners have modified control systems to absorb reactive power during light load periods to hold down the voltage on the sub-transmission network.

A week of engineering time is required to determine the best way to improve the integration of this plant into the TLC network given the changes that have occurred with controllers in recent times. There have also been some recent tripping events at the site which require further analysis.

Piriaka: The work to be completed includes researching the new controllers that have been recently fitted and running network models to see how these can be better integrated into the network. Work is also needed on the commercial connection contracts.

Wairere: As for Kuratau and Piriaka.

Note: All sites have a significant effect on grid exit power factor. (A full explanation of why and how is included in Section 5 of this Plan.) The poor power factor may have a significant impact on grid connection charges if the Electricity Authority and Transpower enforce power factor requirements associated with the Governance Rules. TLC has an exemption from the rules for the Hangatiki Grid Exit and will extend this to other sites.

The tuning of generator plant will become a higher asset management priority as TLC's analysis models are developed, the generation investors fit modern controllers, TLC renews its regulator controllers, TLC updates its protection and reactive power flows are better managed.

3.1.6 Description of the Load Characteristics of different parts of the network

High-level descriptions of the load characteristics of the different parts of the network, grouped in non-electrically contiguous, but abutting, supply regions are outlined in the following sections.

3.1.6.1 Hangatiki region (north western region)

Regional Activities that Affect Load Characteristics

- Industrial loads including iron sand extraction, limestone processing, meat processing, and sawmilling.
- Rural loads include dry stock and dairy farming.
- Run of the river hydro generation.
- Domestic load base of people who are largely employed in the above activities.

Resulting Load Characteristics

The peak system load is dominated by the six weekly cycle of the loading of the iron sands ship. If this loading coincides with dry periods and low river flows, i.e. low distributed generation output, then a grid exit point connection local peak is set.

Limestone and meat processing peaks are seasonal. Both these activities operate for varying periods during the year. Most of the sawmilling operations tend to be 5 ½ days per week, 10 hours per day activities.

Dairy farming is a seasonal activity that produces a peak springtime load. Most dairy farms have a down time between May and August, and two daily peaks when milking is underway.

The cumulative effects of these activities results in a local grid peak in March or April and a late winter/autumn system peak. (System peak is the sum of grid exit and distributed generation inputs.) The system peaks tend to have lower power factors due to the effects of the distributed generation.

3.1.6.2 Whakamaru area (north eastern region or Waikato River area)

Regional Activities that Affect Load Characteristics

- Predominantly a dairy farming area.
- Has a “sub-set” network that supplies the Mokai Energy Park. The Energy Park has two major customers; a glasshouse and a milk plant.

Resulting Load Characteristics

The peak system load in this region occurs early in the dairy season during the overlap of milking and domestic cooking load.

This region of the network is connected to three major generators and is upstream of the grid exit point as detailed in other sections of this Plan. Consequently, it is not directly subjected to Transpower interconnection or connection charges. An additional connection is proposed to increase security for the milk plant.

3.1.6.3 Central region (includes National Park, Tokaanu and Ongarue grid exit points)

Regional Activities that Affect Load Connections

- Holiday homes around Lake Taupo.
- Whakapapa Ski Field.
- Kuratau Distributed Generation.
- Domestic load, Taumarunui.
- Corrections Department load in Turangi area.

Resulting Load Characteristics

The holiday homes around Lake Taupo cause an Easter and school holiday peak on the Tokaanu grid exit point. The timing of this peak depends on which holiday period has the coldest weather. These can occur over cold holiday periods, during the ski season or occasionally at Christmas.

The ski season dominates the peak loading at the National Park grid exit point. During summer there are medium levels of load due to activities such as farming operations, accommodation, and ski field activities such as chairlifts that are run to provide access for trampers. During periods of light load and after heavy rainfall, the Kuratau distributed generation often causes the Ongarue or Tokaanu grid exit points to run backwards.

The load of Taumarunui follows the normal domestic pattern and typically causes a system peak during the winter period. The timing of the grid exit peak is dependent on rainfall, and what the generation is doing during this period. Taumarunui has little industrial load and over recent years the peak demand has increased. The power factors of each of the three grid exit points are reduced whenever the Kuratau, Piriaka and Moerangi distributed generation is connected to them.

3.1.6.4 Ohakune region

Regional Activities that Affect Load Conditions

- Ski season.
- Carrot processing.
- Increasing dairying load.

Resulting Load Characteristics

Peaking load based on winter holiday periods and dependent on weather during the ski season. The conditions during school holiday weekends have a significant effect.

3.1.7 The Peak Demand and Total Electricity Delivered in previous year

The figures on peak demand and energy delivered are based on information from:

- Transpower grid exit metering pulses that go into the SCADA system.
- Whakamaru and Atiamuri large generator connection metering pulses going into the SCADA system.
- Half-hourly metering pulses travelling into the SCADA system from larger distributed generation.
- Estimates for smaller distributed generation and the energy transported between the Winstone Pulp Mill site and the Tangiwai Sawmill.

Table 3.1 lists the total energy transported for non-contiguous, (but abutting) network areas, including estimates for distributed generators and the Winstones arrangement. The 'Average Change (%) p.a.' figures in the table are taken over the last 6 years.

UNITS TRANSPORTED (GWh)									
Electrically Non Contiguous Network Note: Network is non-contiguous, but abuts.	**Notes**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Average Change (%) p.a.**	**2009/10 to 2010/11 % Change**
Northern		185.64	187.69	191.69	194.60	201.58	204.07	1.92%	1.23%
Central	1	98.80	102.75	103.38	103.47	105.00	104.15	1.07%	-0.81%
Ohakune	2	30.75	31.89	32.79	32.92	34.18	33.31	1.64%	-2.55%
Total TLC Network		**315.19**	**322.33**	**327.85**	**330.99**	**340.76**	**341.53**	**1.62%**	**0.22%**

TABLE 3.1: TOTAL ENERGY TRANSPORTED DURING THE 2005/06 TO 2010/11 YEAR

Notes:
1. Includes an estimate for Moerangi Distributed Generation.
2. Includes an estimate for Winstones Mill.

The total energy transported through Northern network continues to increase. Both Central and Ohakune networks have had a drop in total transported energy.

TLC has not been able to source any meaningful metering data, at the time of writing, on the Moerangi generation or Winstones Mill operations.

PEAK DEMAND (MW)								
Electrically Non Contiguous Network Note: Network is non-contiguous, but abuts.	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Average Change (%) p.a.**	**2009/10 to 2010/11 % Change**
Northern	36.42	39.23	39.32	38.30	39.16	39.02	1.45%	-0.36%
Central	25.37	28.02	27.86	24.74	27.40	28.92	2.99%	5.55%
Ohakune	5.32	5.94	7.66	6.42	8.22	8.26	10.59%	0.49%
Co-Incident Demand	57.90	58.44	64.78	61.30	63.50	62.98	1.84%	-0.82%

TABLE 3.2: SYSTEM PEAKS FOR EACH OF THE SUPPLY AREAS

The system peaks (sum of grid exit and distributed generation) for non-contiguous network areas are listed in Table 3.2 for the 2005/06 to 2010/11 years. The figures vary from year to year. The energy transported is increasing at an average of 1.62% while the peak demands are increasing at 1.84%. Central network peak demand had an above average 5.55% increase for the 2009/10 to 2010/11 year. Ohakune network had a small increase in peak demand for the 2010/11 year but overall average increase rate is still relatively high. (One of the reasons why TLC has gone to demand based charges is to try and reduce this trend.)

Data is variable and fluctuates up and down from year to year dependent on many factors. More data is required before conclusive comment can be made on the impacts of demand billing; however, the initial information is encouraging, i.e. it appears that it is helping to slow down the increase in demand. The distributed generation connections complicate the measurement of these values; particularly when there is no half hourly metering or the time clocks, (as has been found), have drifted in time. Further discussion on these findings is included in later sections of this report.

It should be noted that the demand figures in Table 3.2 are anytime and may include the effects of times when TLC is not signalling demand constraints to customers.

3.2 A Description of Network Configuration

3.2.1 Identification of Bulk Electricity Supply Points

3.2.1.1 Arapuni to Bunnythorpe 110 kV system

Figure 3.2 illustrates a simplified layout of the Hangatiki, Ongarue, National Park, and Ohakune grid exit points.

Supply to the Hangatiki grid exit point is via two Transpower circuits from Arapuni or one from Bunnythorpe. The southern Bunnythorpe circuit has Ongarue, National Park, Ohakune and Mataroa connected to it. (Mataroa is not a TLC supply point.)

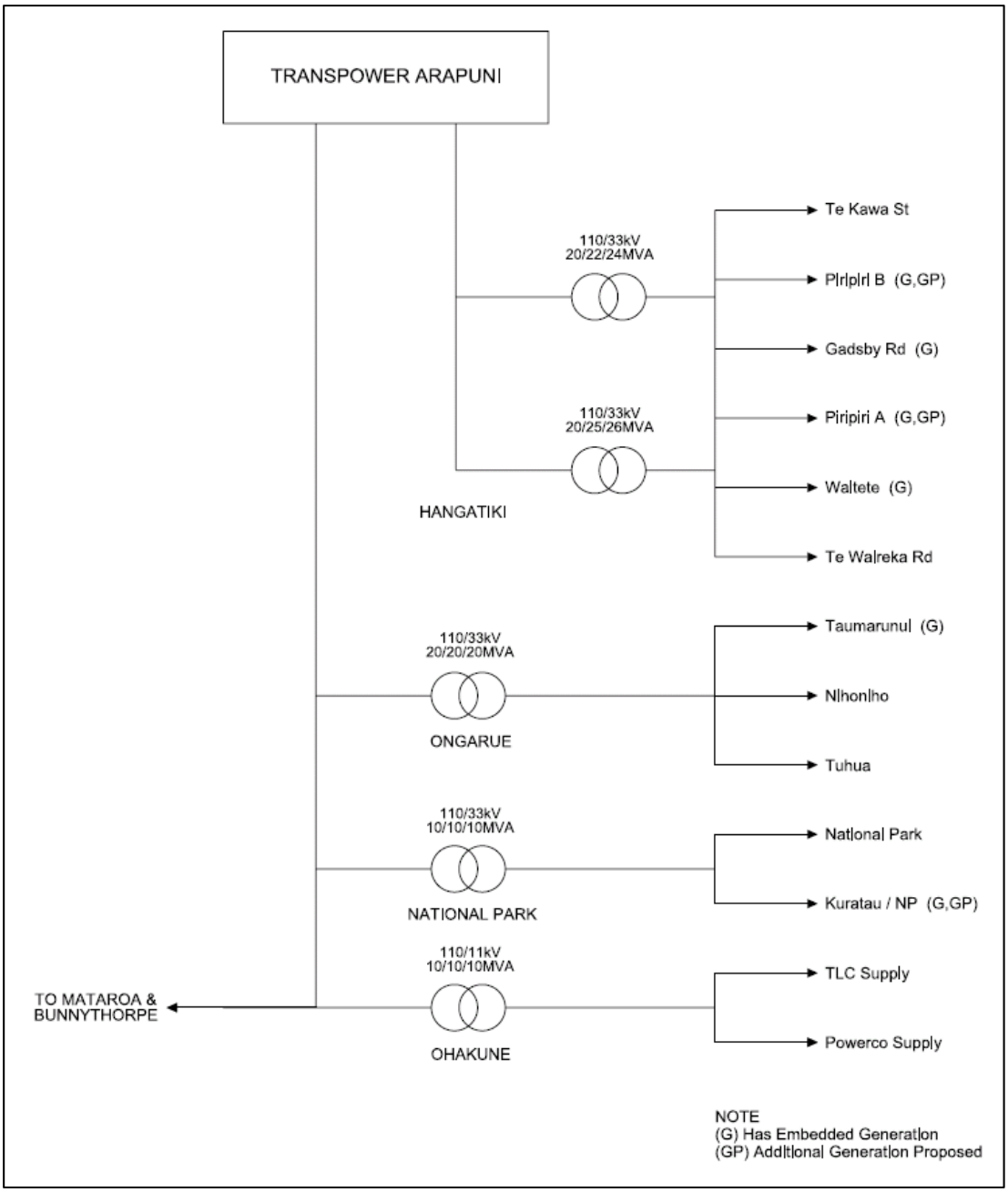


FIGURE 3:2: SIMPLIFIED SINGLE-LINE DIAGRAM OF THE HANGATIKI, ONGARUE, NATIONAL PARK, AND OHAKUNE GRID EXIT POINTS

Note: Transformer Ratings: Maximum Continuous/Summer/Winter. Ohakune has the only regulated transformer supply. The tee into Hangatiki from the circuit going south is about 6km from the substation.

3.2.1.2 Tokaanu

Figure 3.3 illustrates the arrangement at Tokaanu whereby TLC takes energy from Transpower via two 220/33 kV transformers. These transformers are unregulated.

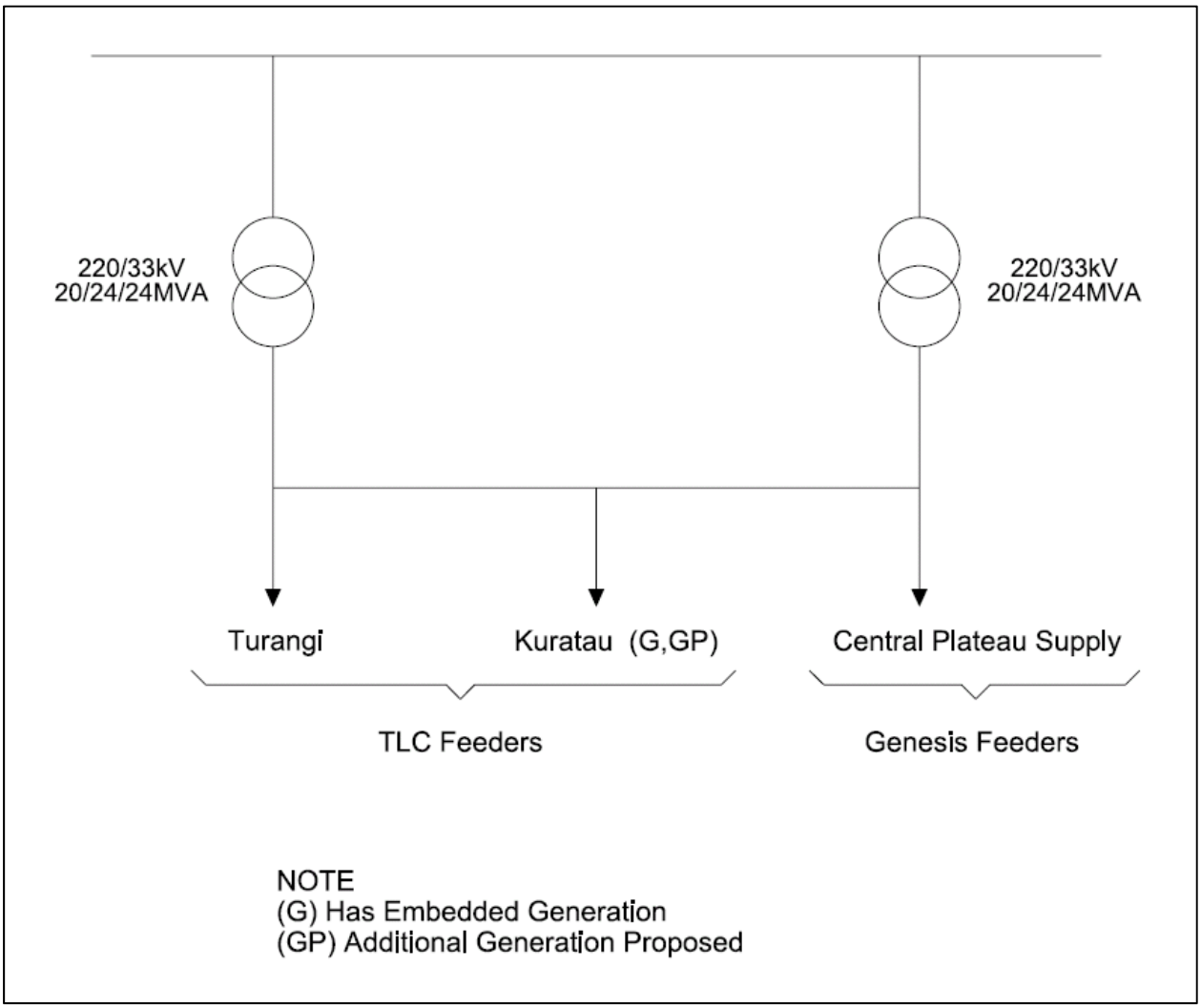


FIGURE 3.3: TOKAANU CONNECTION DETAIL

Note: Transformer Ratings: Maximum Continuous/Summer/Winter.

3.2.1.3 Whakamaru and Atiamuri

Figure 3.4 illustrates the arrangement at Whakamaru where energy comes directly from either the Mokai investor owned geothermal station or Mighty River Power (MRP) G4 generator.

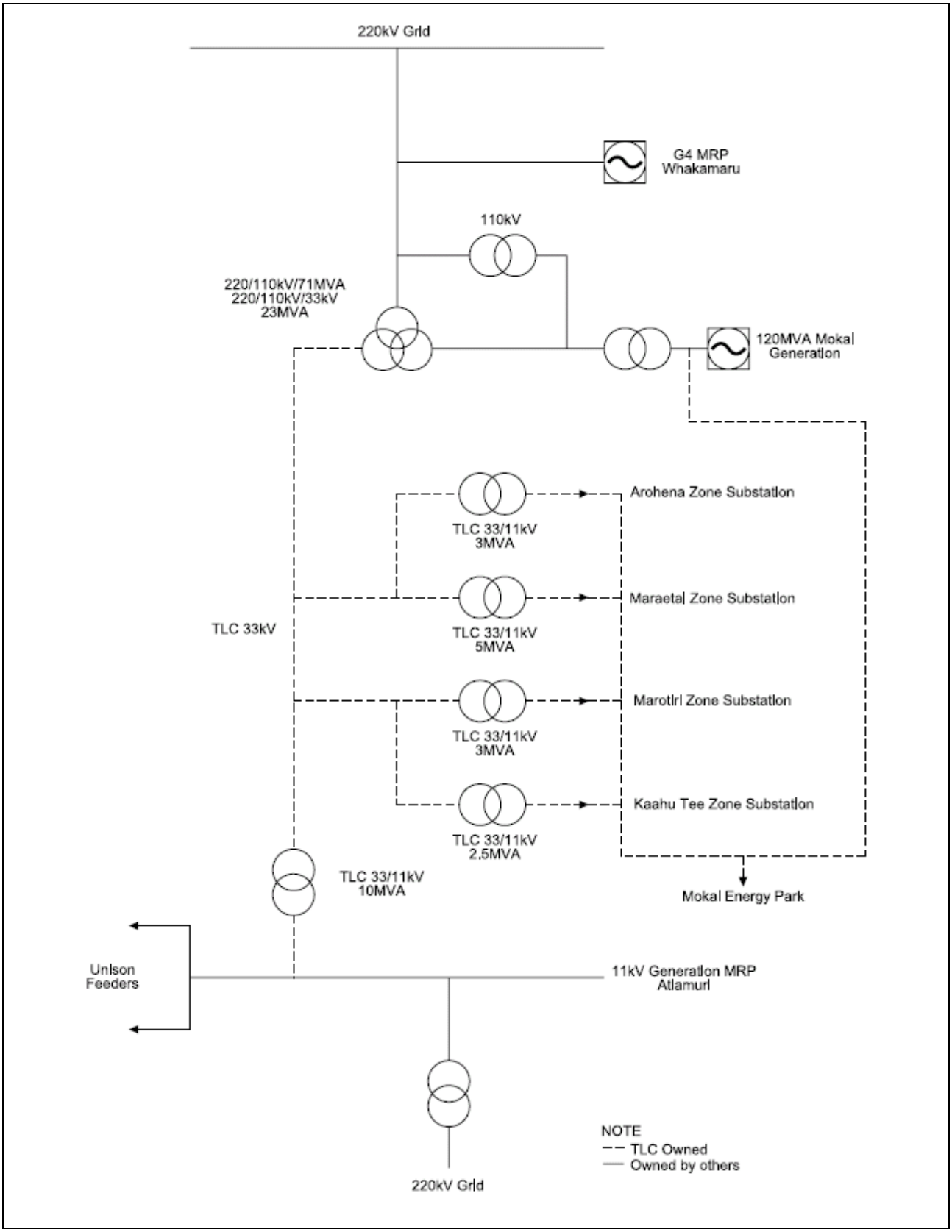


FIGURE 3.4: WHAKAMARU AND ATIAMURI CONNECTION DETAIL

Note: Transformer Ratings: Maximum Continuous/Summer/Winter

The TLC network is connected to a three-winding transformer that transforms the 110 kV output from Mokai to the 220 kV G4 generation bus. The third winding on this transformer supplies the TLC network. This network also has another connection and alternative supply via a TLC 33 kV line from the MRP Atiamuri site. This bus also connects to another power company network and the grid via 11/220 kV transformation. Mokai and/or G4 are run to supply TLC, and the connection contracts at these points are not with Transpower.

The link also gives MRP the ability to shut down Atiamuri and supply Unison network customers via the TLC network during periods of controlled river flow control. A third interconnection between TLC and the Mokai generation is used to principally supply the Mokai Energy Park.

The arrangement at Whakamaru and Atiamuri is unique and one that means that the TLC network is operating a mini transmission grid in parallel with Transpower. This arrangement came about when Transpower decided it wanted to increase the cost of supply into the area significantly as a consequence of its decision to decommission the Waikato 50 kV system in the late 1990s. The best solution found at the time was for TLC to purchase the 50 kV Atiamuri to Arohena segment of Transpower assets, including the Arohena, Maraetai, Kaahu Tee and Marotiri substations, convert the sub-transmission to 33 kV, and connect the substations to Mokai and Whakamaru G4 outputs. The development of the Mokai Energy Park resulted in the need for an off-take to supply this from the Mokai geothermal generation.

3.2.1.4 Ohakune emergency supply

TLC has assets in place to take an 11 kV connection from Winstone's plant at Ohakune. This supply comes via the Transpower 220 kV to 11 kV supply to the mill. TLC has a metered tap off via an 11 kV remotely controlled circuit breaker back into the Ohakune network.

The supply is used to:

- Supply Ohakune when the Transpower Ohakune grid exit point connection is out of service for planned and unplanned work. (The connection cannot supply the total Ohakune load during the winter period.)
- Supply the mill during maintenance periods when the 220/11 kV supply to the mill is not available. The connection is not capable of running the mill operation, but allows the site to be energised for maintenance activities.
- In an emergency, when the 15km 11 kV line between the mill and Ohakune is not available, this supply can be used for the Whangaehu Valley area.

Allowances are included in the Plan to make this supply permanent as running the supply from the Winstones Pulp Mill is complex from the operational, energy market and Transpower interconnection/connection perspective. It will be used to buy headroom at Ohakune until the Transpower transformers have been upgraded. There are also hazard control issues associated with the supply capacity.

3.2.2 Embedded Generators Connected to bulk electricity supply points greater than 1 MW

Table 3.3 details the embedded generation and which grid exit points it can be connected to.

EMBEDDED GENERATION			
Distributed Generation	**Size (MW)**	**Grid Exit Point (Normally Connected)**	**Other Switchable Options**
Kuratau	6	Ongarue	National Park, Tokaanu
Piriaka	1.5	Ongarue	National Park, Tokaanu
Wairere	5	Hangatiki	Whakamaru (Limited)
Mokauiti 1	1.5	Hangatiki	Whakamaru (Limited)
Mangapehi	2.5	Hangatiki	Whakamaru

TABLE 3.3: EMBEDDED GENERATION CONNECTED TO GRID EXIT POINTS GREATER THAN 1 MW CAPACITY

3.2.3 Existing Firm Supply Capacity and Current Peak Load of each supply point

Table 3.4 lists the existing firm supply capacity and current peak load of each supply point.

FIRM SUPPLY POINT CAPACITY AND PEAK LOAD				
Grid Exit Point	**Capacity Arrangement**	**Current Peak (2010/11 Year) (MW)**	**(MVA)**	**Power Factor**
Hangatiki	1 x 20/22/24 1 x 20/25/26	28.262	31.828	0.888
Ongarue	1 x 20/20/20	10.090	10.185	0.991
National Park	1 x 10/10/10	6.730	6.886	0.977
Ohakune	1 x 10/10/10	8.028	8.170	0.983
Tokaanu	2 x 20/24/24	8.572	8.624	0.994

TABLE 3.4: SUPPLY CAPACITY AND CURRENT PEAK LOAD AT EACH GRID EXIT POINT

Note: Whakamaru is not a grid exit point as it is upstream of Transpower assets thus it has not been included in this table.

The Hangatiki grid exit point is presently peaking above its firm (n-1) capacity at times when generation is not available. The Ohakune supply point is expected to reach full transformer capacity with ski field expansion.

One of the significant effects of distribution generation is to reduce the grid exit power factors. This occurs at the Hangatiki and Ongarue and Tokaanu grid exits. This reducing power factor effect is discussed further in later sections.

Note: The Ongarue peak is when generation was not available and, as such, the power factor reduction effect is not occurring at this time.

3.2.4 Description of the Sub-transmission System fed from the bulk supply points, including identification and capacity of zone substations

3.2.4.1 Sub transmission 33 kV lines

Figure 3.5 shows geographically the layout of the sub-transmission system.

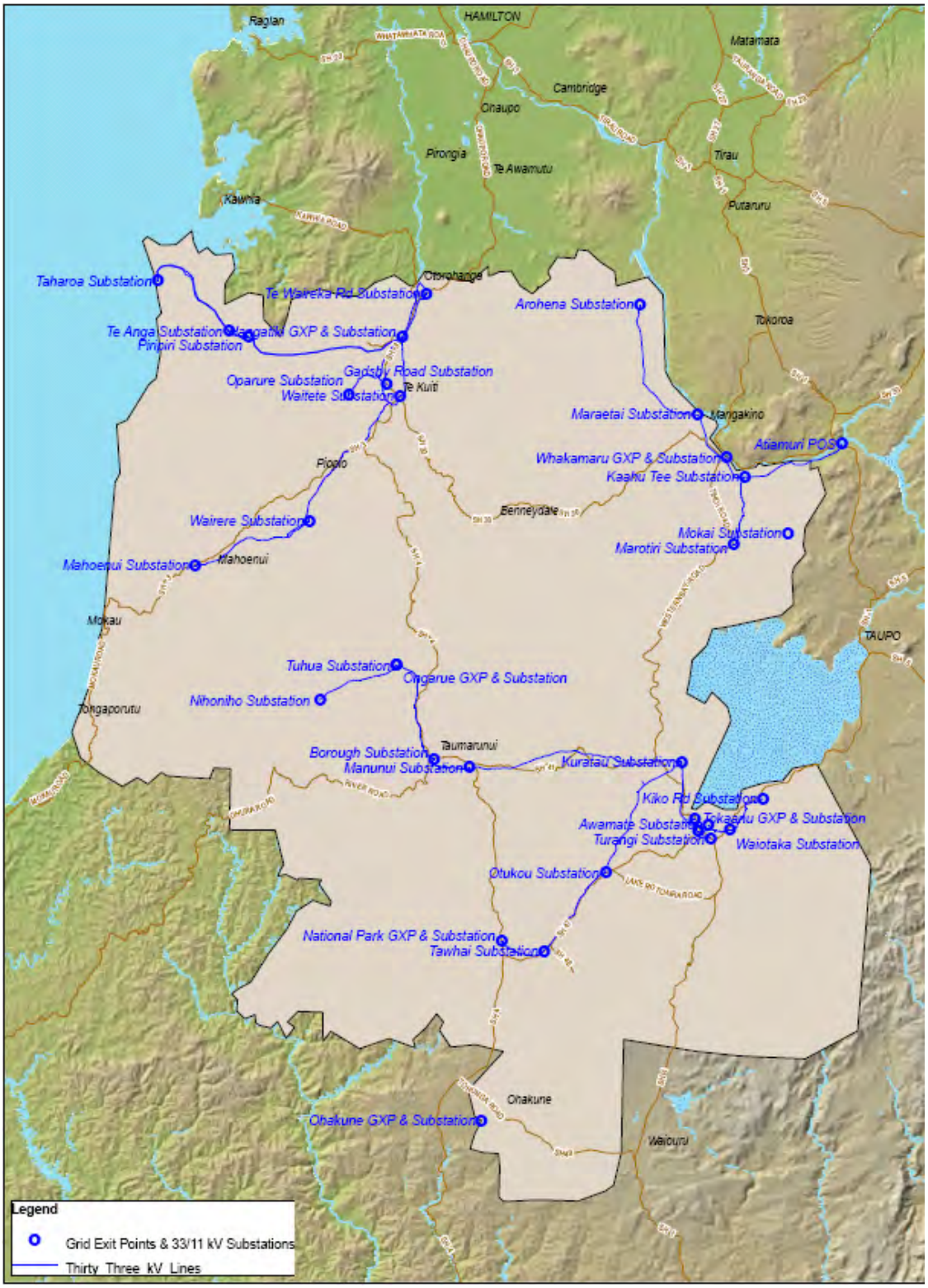


FIGURE 3.5: LAYOUT OF SUB-TRANSMISSION NETWORK

The specific configuration description of each of the sub-transmission line assets is included in Table 3.5.

SUB-TRANSMISSION ASSET CONFIGURATION		
Description	**Configuration Description**	**Backup Security**
HANGATIKI SUPPLY POINT		
Gadsby / Wairere 33 Overhead: 32.77km Underground: 0.00km	Part of ringed network linking Te Kuiti.	About 5% of the time it can be backed up by Wairere generation provided 11kV links made and generator very carefully controlled.
Gadsby Rd 33 Overhead: 17.4km Underground: 0.00km	Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP. At the end of the planning period, these lines will be at full rating. Travels through hill country. Operated in closed ring.	Waitete 33kV. Backed up to about 75% of present full load. (Back up has difficulty when load is high and river flows are low).
Mahoenui 33 Overhead: 22.57km Underground: 0.00km	Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. Considerable DG resource in area that is under investigation. Travels through hill country.	11kV backup for about 15% of time when light loads exist.
Taharoa A 33 Overhead: 53.51km Underground: 0.00km	Iron Sand Taharoa and future DG sites. Some local rural supply also.	Backed up to full load by Taharoa B line.
Taharoa B 33 Overhead: 45.87km Underground: 0.00km	Supply to Iron sand Taharoa and future DG sites. Some local rural supply also. Line is not on roadside. Travels through hill country. Operated in closed ring.	Taharoa A line. Backed up to present full load.
Te Kawa St 33 Overhead: 12.05km Underground: 0.00km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed. Travels through hill country. Operated in closed ring.	Te Waireka 33kV line. Backed up to present full load.
Te Waireka Rd 33 Overhead: 8.22km Underground: 0.00km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed. Travels through hill country. Operated in closed ring.	Te Kawa 33kV line. Backed up to present full load.
Waitete 33 Overhead: 10.79km Underground: 0.00km	Part of ringed network linking Te Kuiti.	Gadsby Road. Backed up to about 75% of present max loading.
NATIONAL PARK SUPPLY POINT		
National Park / Kuratau 33 Overhead: 57.25km Underground: 0.00km	Line travels across difficult access country and sensitive Maori land.	Backup from Kuratau up to about 25% load. In practical terms this means (n-1) except for ski season.
National Park 33 Overhead: 0.04km Underground: 0.00km	Few metres of spur line connecting National Park GXP to zone substations.	50 % load backup from 11kV network.

SUB-TRANSMISSION ASSET CONFIGURATION		
Description	**Configuration Description**	**Backup Security**
ONGARUE SUPPLY POINT		
Nihoniho 33 Overhead: 14.59km Underground: 0.00km	Spur line connecting Ongarue GXP to Nihoniho 33 Zone Substation. Line runs through very hilly remote country with poor access.	50% load backup on 11kV from Tuhua. (Voltage drop is main issue).
Ongarue / Taumarunui 33 Overhead: 18.21km Underground: 0.36km	Main line supplying Taumarunui from the Ongarue GXP. Line runs through extremely hilly country.	50% load backup from Tokaanu provided Kuratau and Piriaka generation running.
Taumarunui / Kuratau 33 Overhead: 38.02km Underground: 0.00km	Line travels across difficult access country.	Backup from National park GXP and Tokaanu (n-1) depending on generation and ski season.
Tuhua 33 Overhead: 0.08km Underground: 0.00km	Few metres of spur line connecting Ongarue GXP to Tuhua zone Substation.	50% load backup from Nihoniho on 11kV network.
TOKAANU SUPPLY POINT		
Lake Taupo 33 Overhead: 31.78km Underground: 0.91km	Spur line connecting Tokaanu GXP to the Kiko Road zone substation. Crosses many plots of extremely sensitive Maori land.	No backup, Generators have to be used to back this line up.
Tokaanu / Kuratau 33 Overhead: 15.53km Underground: 0.44km	Line travels across difficult access country and extremely sensitive Maori land.	Backup from National Park GXP and Ongarue via Taumarunui. (n-1) depending on generation and ski season.
Turangi 33 Overhead: 2.94km Underground: 0.00km	Spur line connecting Tokaanu GXP to the Turangi Zone Substation. Crosses sensitive Maori land.	Light to medium load backup
WHAKAMARU SUPPLY POINT		
Whakamaru 33 Overhead: 112.38km Underground: 0.00km	Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai and Marotiri zone substations. Travels through hill country.	Very limited backup capacity (about 10%) through the 11kV network.

TABLE 3.5: SUB-TRANSMISSION ASSETS CONFIGURATION DESCRIPTION

3.2.4.2 Sub-transmission zone substations

A general summary description of zone substations is included in Table 3.6:

ZONE SUBSTATION ASSET SUMMARY	
Assets	**Number**
Site Development and buildings	36
Transformers	38
33 KV breakers excluding Fault Thrower Switches	38
11 KV breakers	79
Switch Gear related equipment	186
Protection and controls	Various
Other equipment including Remote Terminal Units (RTUs), communications, load control injection, Direct Current (DC) supplies, and batteries	Various

TABLE 3.6: ZONE SUBSTATION ASSET SUMMARY

3.2.4.3 Specific details of the extent zone substations have (n-x) security

Table 3.7 details each of the zone substations and information on security.

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
Arohena Zone Substation	1 @ 3000 kVA	Light load backup from 11kV network. This backup will not support the milking load in the area. In practical terms this means (N).
Atiamuri Point Of Supply	1 @ 10000 kVA	Site is backed up from 33kV network and MRP Atiamuri generation. Back up Whakamaru and is part of the innovative arrangement to take supply directly from generators and by pass transmission charges. In practical terms this means (N).
Awamate Zone Substation	1 @ 2000 kVA	Part of backup network for Turangi. Backup from Turangi. In practical terms this means (N) transformers.
Borough Zone Substation	2 @ 5000 kVA	Site is not fully backed up. 1x5MVA will not support all load at peak times. The site has a single 11kV bus with no bus coupling capability. Limited light load backup is available from 11kV network. In practical terms this means (N-1) transformers.
Gadsby Road Zone Substation	1 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N).
Hangatiki Zone Substation	1 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N).
Kaahu Tee Zone Substation	1 @ 2400 kVA	Embedded in Marotiri / Maraetai network. Backup from Marotiri/Maraetai. Cannot be taken out of service during heavy load times. In practical terms this means (N).
Kiko Road Zone Substation	1 @ 3000 kVA	No backup available other than bypassing sub and injecting 11kV from Turangi into 33kV line. This is light load backup only. In practical terms this means (N).

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
Kuratau Zone Substation	1 @ 3000 kVA 1 @ 1500 kVA	3 MVA transformer in aged condition. 1.5 MVA backup available on site (This will not cover full load situations) (Backup will also not phase so an outage is needed to transfer load). In practical terms this means (N). Old backup unit for emergencies only. Will not supply heavy load and does not phase. Emergency use only. Will be decommissioned and replaced with Piripiri transformer in the planning period. In practical terms this means (N).
Mahoenui Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Manunui Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Maraetai Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. This backup will not support the milking load in the area. In practical terms this means (N).
Marotiri Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. This backup will not support the milking and industrial load in the area. In practical terms this means (N).
National Park Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Nihoniho Zone Substation	1 @ 1500 kVA	Light load backup from 11kV system. In practical terms this means (N).
Oparure Zone Substation	1 @ 3000 kVA	Principally supplies an industrial site. Forward plan is to utilise transformer more for supplying into local 11kV network. Light load backup available. In practical terms this means (N).
Otukou Zone Substation	1 @ 500 kVA	No backup or alternative feed security. In practical terms this means (N).
Piripiri Zone Substation	1 @ 1500 kVA	Old transformer was decommissioned in December 2010. Backup possible by reconfiguring Taharoa 33kV line and operating at 11kV. Constructed for Speedys Road Hydro and replaces Piripiri Zone Substation. In practical terms this means (N).
Taharoa Zone Substation	3 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N-1).
Tawhai Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Te Anga Zone Substation	1 @ 2000 kVA	Site has firm line and transformer capacity in theory. It does have a single 11kV bus with no bus coupler. The site is very exposed and reliability due to weather extremes is an issue. In practical terms this means (N).
Te Waireka Zone Substation	2 @ 10000 kVA	Firm transformer capacity feeding a single 11kV bus with no bus coupler. Limited light load backup available from 11kV network. In practical terms this means (N-1) transformers.
Tokaanu Village Zone Substation	1 @ 1250 kVA	33kV to 400V transformer injecting into the 400V network. This is stepped up to give a low load low cost backup to the main 33kV to 11kV transformer for emergencies or during maintenance. In practical terms this means (N). No transformer or 11kV backup. Limited backup via 33kV to 400V step-up to 11kV. In practical terms this means (N).

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
Tuhua Zone Substation	1 @ 1500 kVA	Full load backup from 11kV system. In practical terms this means (N-1) transformers.
Turangi Zone Substation	2 @ 5000 kVA	Site has two transformers with firm transformer capacity but the 33kV supply and 11kV outgoing configuration is weak. There is no 11kV backup available. In practical terms this means (N-1) transformers.
Waiotaka Zone Substation	1 @ 1500 kVA	Modular substation 75% backed up from Turangi 11kV. In practical terms this means (N).
Wairere Zone Substation	2 @ 2500 kVA	One transformer capacity and 11kV network connections will support connected load customers but not generation customers. In practical terms this means (N-1) transformers.
Waitete Zone Substation	3 @ 5000 kVA	Normal operating loads are in the 6 to 7 MVA range. The site has firm capacity in its present configuration. Limited backup is available from the 11kV network. In practical terms this means (N-1) transformers.
Whakamaru Point of Supply	1 @ 23000 kVA	TLC owner winding only on jointly owned transformer. Backed up from Atiamuri. Note: this is an non standard arrangement put in place to lower and avoid Transpower charges for this area. In practical terms this means (N).

TABLE 3.7: EXTENT TO WHICH INDIVIDUAL ZONE SUBSTATIONS HAVE (N-X) SUB-TRANSMISSION SECURITY

3.2.5 Configuration Description of the Distribution System including the extent to which it is underground

3.2.5.1 Distribution 11 kV lines

The major distribution assets are 11 kV overhead lines. Table 3.8 describes these assets on a feeder-by-feeder basis.

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Aria	77.91	Aria Rural area		
Benneydale	133.68	South east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats.	0.07	Cable out of zone substation
Caves	65.14	Waitomo village and rural area to the west.	0.30	Cable out of zone substation
Chateau		Whakapapa Ski field and village , About 60% is heavy armoured cable	28.60	Cable on mountain
Coast	84.09	Remote rural area around Marokopa		
Gravel Scoop	94.91	South east of Otorohanga	0.22	Cable out of zone substation.
Hakiaha	3.82	Central area of Taumarunui	1.93	Cable in CBD Taumarunui
Hangatiki East	19.91	Area east of Hangatiki	0.07	Cable out of zone substation
Hirangi	6.55	SWER feeder to semi residential area around Turangi	0.15	Cable into substation
Huirimu	44.91	Supply to rural area south of Arohena		
Kuratau	34.38	Supply to Kuratau Village area	3.56	Cable in parts of township
Mahoenui	107.68	Supply to Mahoenui and surrounding rural areas	0.10	Cable to ground mount transformers in Mokau and Awakino
Maihiihi	101.51	Rural area north east of Otorohanga	1.06	Cable out of zone substation.
Mangakino	20.81	Supply to Mangakino	2.13	Cable out of zone substation.
Manunui	86.83	Rural area to south and east of Taumarunui	0.92	Cable to ground mount transformers in Manunui
Matapuna	14.79	Supply to western side of Taumarunui	2.02	Cable in urban area of Taumarunui
McDonalds	36.74	Rural area to the south of Otorohanga	0.80	
Miraka	0.20	Supply to Mokai Energy Park, Miraka Milk and other customers	0.71	Not practical to construct overhead lines in these areas
Mokai	74.26	Mokai rural area	1.47	Cable to new subdivision
Mokau	129.72	Mokau coastal area		
Mokauiti	74.21	Rural area south west of Piopio		
Motuoapa	1.86	Supply to Motuoapa area	0.64	Cable to new subdivision
National Park	44.37	Supply to the National park area including the village	0.19	Cable to ground mount transformers in village

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Nihoniho	30.25	Supply to the Nihoniho and Matiere areas		
Northern	121.37	Area north of Taumarunui	2.97	Cable in urban area of Taumarunui
Ohakune Town	9.44	Ohakune town supply	3.49	Cable in Ohakune CBD
Ohura	181.54	Ohura and surrounding remote rural areas	0.13	Cable to ground mount transformers
Ongarue	122.19	Large rural area around Ongarue		
Oparure	75.45	Supply to an area west of Te Kuiti	5.42	Cable in urban area of Te Kuiti
Oruatua	7.25	Eastern side of Lake Taupo, north of Motuoapa	1.68	Cable to new subdivision
Otorohanga	52.00	Supply to most of town plus rural area to southwest	1.35	Cable in Otorohanga CBD and out of zone substation
Otukou	6.47	Area around Sir Edmund Hillary Outdoor Pursuits Centre		
Paerata	3.57	Supply to Mokai Energy Park, Glasshouse and other customers	0.45	Not practical to construct overhead lines in these areas
Piopio	54.95	Supply to Piopio village and surrounding rural area to north	0.10	Cable to ground mount transformers in village.
Pureora	52.05	West of Whakamaru including supply to Crusader Meats	0.06	Cable out of zone substation.
Rangipo / Hautu	36.30	Supply to areas east of Turangi	6.09	Cable across Tongariro River and at prison
Rangitoto	74.60	Area west of Te Kuiti	2.66	Cable in urban area of Te Kuiti
Raurimu	171.44	Raurimu village and rural areas to east ,west and south		
Rural	5.95	Rural area surrounding Taharoa	0.03	Cable to ground mount transformers
Southern	124.38	Area south of Manunui including connection for Piriaka distributed generation		
Tangiwai	88.94	Area east of Ohakune	1.91	Cable to subdivision
Te Kuiti South	40.17	Part of Te Kuiti town and rural area to south.	1.11	Cable from substation and in urban area of town
Te Kuiti Town	1.26	Central area of Te Kuiti	0.78	Cable from substation and in urban area of town
Te Mapara	62.76	Area south east of Piopio	0.10	Cable from substation
Tihoi	62.47	Western bays area - Lake Taupo		
Tirohanga	71.77	Western bays area - Lake Taupo	4.88	Cable to subdivision
Tokaanu		Tokaanu Town and marina	1.21	Cable in urban area and supply to marina
Tuhua	40.81	Remote rural area around Ongarue		

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Turangi	0.94	Supply to Turangi Town and surrounding area	7.67	Cable in urban areas
Turoa	35.73	Turoa ski field and urban rural area to bottom of mountain	24.21	Cable in urban area and at ski field
Waihaha	113.65	Area around south western of Lake Taupo	2.31	Cable to Whareroa holiday area
Waiotaka	9.01	Was originally part of the Rangipo Hautu feeder prior to the Waiotaka Substation being constructed	1.18	Cable at prison
Waitomo	11.20	Area north of Te Kuiti and major lime plant	0.70	Cable from substation and urban area of Te Kuiti
Western	135.34	Rural area north west of Taumarunui	1.19	Cable from substation and in urban area of Taumarunui
Whakamaru	68.72	Whakamaru village and surrounding dairying areas	0.03	Cable from substation
Wharepapa	105.95	Large rural dairying area west of Arohena	0.48	
Total	**3,236.19**		**116.98**	

TABLE 3.8: DISTRIBUTION OF 11 KV DISTRIBUTION LINES

3.2.5.2 SWER systems configuration description

Table 3.9 lists and describes the SWER systems used by TLC. All except the Tokaanu River and Pihanga system operate at 11 kV to earth. The Tokaanu River and Pihanga systems operate at 6.6 kV to earth. All SWER systems are fed by isolation transformers. Many of the systems have back feed options, which generally are not in phase and all switching has to be completed with supply removed.

SWER SYSTEM CONFIGURATION				
Feeder	**Location**	**Transformer ID**	**Isolation TX kVA Rating**	**Total kVA of Connected Transformers**
Aria	Kumara Road	T1948	200	210.00
Benneydale	Kopaki Road	T2506	100	256.00
Benneydale	Waimiha Road	T1454	100	152.50
Caves	Kokakoroa road	T1185	15	60.00
Coast	Mangatoa Road	T2363	100	147.50
Hirangi	Hirangi	10S05	100	102.50
Kuratau	Parerohi Grove	T4282	100	120.00
Kuratau	Pukawa	09R02	100	182.50
Kuratau	Waihi	09R27	200	215.00
Kuratau	Waihi Pukawa Trust	T4233	25	5.00
Mahoenui	Haku Road	T2520	50	103.00
Mahoenui	Mangaoronga Road	T1865	100	138.00
Mahoenui	Mangaotaki Road	T1692	68	212.50
Mahoenui	Pungarehu Road	T1453	100	18.00
Manunui	Kirton Road	08J07	200	379.00
Manunui	Ngapuke	08L17	200	493.00
Manunui	Waituhi	07K11	100	97.50
Mokau	Clifton road	T2194	100	80.00
Mokau	Manganui road	T2166	100	415.50
Mokau	Mohokatino road	T2177	100	122.50
Mokau	SH40 - Tongaporutu	T2208	100	325.50
Mokauiti	Mokauiti road	T827	200	430.50
Nihoniho	Nihoniho	06E01	100	208.50
Northern	Hikurangi	T4055	200	605.00
Northern	Okahukura	06H11	200	468.00
Ohura	Aukopae	T4130	100	110.00
Ohura	Huia road	07D11	100	213.00
Ohura	Opatu	10E09	100	413.00
Ohura	Tatu	09C05	200	168.00
Ohura	Waitaanga	07D08	200	248.00
Ohura	Waitewhena	07D16	100	158.00
Ongarue	Koromiko	02K16	100	267.50
Ongarue	Ongarue	04I01	100	568.50
Ongarue	Tapuiwahine	T4128	100	255.50

SWER SYSTEM CONFIGURATION				
Feeder	**Location**	**Transformer ID**	**Isolation TX kVA Rating**	**Total kVA of Connected Transformers**
Ongarue	Waimiha	02K08	100	380.00
Oruatua	Tauranga-Taupo	T4087	25	15.00
Oruatua	Waitetoko	09U12	100	130.00
Otukou	Otukou	12O01	100	356.00
Rangipo / Hautu	Korohe	T4172	100	150.00
Rangipo / Hautu	Tokaanu river	T4133	25	15.00
Rangitoto	Gardiner road	T678	25	35.00
Raurimu	Retaruke 1 (lower)	13I10	100	433.00
Raurimu	Retaruke 2 (upper)	T4132	100	290.00
Raurimu	Ruatiti	T4077	100	426.50
Southern	Kaitieke	11K11	100	227.50
Southern	Kawautahi	T4239	200	428.50
Southern	Makokomiko	09K25	100	303.00
Southern	Oio road	12K08	100	236.00
Southern	Otapouri	10K14	200	401.00
Southern	Tunanui	09K02	100	242.50
Te Mapara	Main south road - Te Kuiti	T1777	100	228.50
Te Mapara	SH4 - Aramatai	T1829	100	335.50
Tihoi	Tihoi	T1618	200	425.50
Tokaanu	Tokaanu Zone sub	T4271	50	50.00
Tuhua	Matiere	05F14	200	454.00
Tuhua	Tuhua	05G03	100	216.50
Waihaha	Karangahape road	T4193	200	458.50
Waihaha	Kuratau	07Q14	200	527.50
Waihaha	Waihaha	04Q06	200	272.50
Waiotaka	Hautu	10S18	100	50.00
Western	Kirikau	09H01	100	383.00
Western	Otunui	T4131	100	275.00
Western	Pongahura	08H03	100	275.00
Western	River road	08I21	200	381.00

TABLE 3.9: DESCRIPTION OF SWER LINES

It should be noted that systems with more than (approx.) 225 kVA connected will be operating over the 8 amp limit in the Single Wire Earth Return (SWER) system code of practice (ECP41). Approximately 60% of the systems in Table 3.9 exceed this. Since 2002, a number of the systems have been broken up and the connected kVA reduced. Previously there were four with greater than 1000 kVA. This work, i.e. installing extra isolation transformers, has been part of line renewal, network development, and new customer connection programmes. Records suggest that these systems had more than the code of practice limit since their construction, which pre-dates the ECP41 code. (Note: This code is in the process of being redrafted to allow currents of greater than 8 amps; the focus of the new code will be limiting hazardous earth potential rises.)

TLC has been working to redraft the code to align better with the operation of the SWER systems and its inclusion in the Electricity Safety Regulations 2010.

3.2.5.3 11 kV cables

Included in distribution feeder assets in Table 3.8 are 11 kV cables.

These cables are dispersed throughout the network but the areas with most significant cabling are:

- Feeders coming out of Te Waireka (Otorohanga), Waitete (Te Kuiti) and Borough (Taumarunui) zone substations.
- Parts of Taumarunui.
- Turangi town (ex hydro construction town).
- Whakapapa Ski Field.
- Turoa Ski Field.
- Recent subdivisions.
- Short sections connecting overhead lines to ground mounted transformers. (See earlier 11 kV feeder descriptions for more specific detail.)
- The Mokai Energy Park.

About 50% of The Lines Company 11 kV cable is associated with the ski field supplies. Much of this cabling has been laid directly on solid rock and uses heavily armoured cables.

Much of the ski field cabling installation does not comply with codes. The long-term strategy is to improve these installations whenever customers or other events such as emergent work and hazard elimination/minimisation projects trigger alterations in the vicinity.

3.2.5.4 Distribution switchgear

Distribution switchgear and control equipment is spread throughout the network. Table 3.10 summarises the identified distribution switchgear and control assets.

11 kV DISTRIBUTION SWTICHGEAR AND CONTROL ASSETS	
Type of Link	**Number**
11 kV ABS Load Break	11
11 kV ABS Two and Three Phase	436
11 kV Circuit Breakers	140
11 kV Fuses in Transformers	805
11 kV Line Reclosers	90
11 kV Oil Switches	4
11 kV Ring Main Units	83
11 kV RTE Integrated Transformer Switches	46
11 kV Sectionalisers	72
11 kV Solid Isolating Links	427
11 kV Transformer Fuses	4765

TABLE 3.10: 11 KV DISTRIBUTION SWITCHGEAR AND CONTROL ASSETS

3.2.6 Brief Description of the Network's Distribution Substation Arrangements

The TLC network uses distribution transformer arrangements similar to most New Zealand networks.

3.2.6.1 Overhead Distribution Substation Arrangements

Typically, supply comes in via 11 kV cut-out fuses and into the transformer. A lightning arrestor is installed between the cut-out fuse and the transformer. The transformer is normally pole mounted. Supply away from the transformer is usually protected with low voltage fuses at about 50% of sites. Transformer sizes typically range from 5 kVA to 200 kVA.

3.2.6.2 Ground Mounted Transformers

Most ground-mounted transformers on the TLC network are tapped off an overhead line via 11 kV cut-out fuses. For lengths of cable greater than 100 metres distribution standards require some form of 3-phase isolation is used to stop Ferro resonance effects.

Cables are normally protected with riser class lightning arrestors at the overhead line end. Various transformer housing arrangements have been used to house the transformers, i.e. from modified garden sheds to I tanks. Most modern types are mainly housed in manufacturers modular I tanks or double door configuration depending on what is most suitable for a particular location. Most low voltage circuits away are fused and many installations have MDIs and transformer isolators. (Current distribution standards require transformer isolators, MDI's and for each circuit away to be protected).

Historically, up to ten transformers have been supplied from one set of 11 kV cut-out fuses protecting daisy-chained arrangements. Sometimes "dry well" fuses have been installed at each individual transformer. The present standard is to install Magnafix or equivalent ring main equipment and rotary transformer switches at alternate sites when connecting units in series. Vacuum non SF6 gas switches that have circuit breaker and automation options are used where appropriate at industrial or major sites on 11 kV feeders.

(The staggering of rotary switches and ring mains minimises costs whilst allowing hazard control expectations to be met).

The identified transformer and substation site assets are summarised in Table 3.11.

DISTRIBUTION TRANSFORMER AND SUBSTATION SITE ASSETS		
Phases	**Description**	**Number**
1	Ground Mounted	19
1	Pole Mounted	2,910
2	Pole Mounted	206
3	Ground Mounted	421
3	Pole Mounted	1,422

TABLE 3.11: DISTRIBUTION TRANSFORMER AND SUBSTATION SITE ASSETS

Note: A number of sites have transformers operating in parallel. The cost relativity of modern transformers means that most new sites tend to have one transformer as opposed to two operating in parallel. Industrial sites do however usually have several transformers supplying various load centres around the plant.

3.2.7 400 Volt Systems

3.2.7.1 400 Volt Distribution Systems

The majority of the LV network is overhead line utilising bare copper (Cu) and aluminium (Al) conductors. An increasing proportion however will become insulated as older conductors are renewed over time as present distribution standards require low voltage overhead conductors to be insulated.

A simplified breakdown of the LV assets is shown in table 3.12.

BREAKDOWN OF LV ASSETS	
Description	**Volume**
LV Concrete	28.7 km
LV Concrete Underbuilt	55.8 km
LV Wood	146.8 km
LV Wood Underbuilt	158.9 km
Streetlight Concrete Underbuilt	18.7 km
Streetlight Wood Underbuilt	89.3 km
Underground Cables	183.59 km
Pillar Boxes	3707 units

TABLE 3.12: BREAKDOWN OF LV ASSETS

Low voltage underground cables exist, to some extent, in most township areas. Turangi town has the most extensive low voltage cable network.

The identified cabling assets consist of 183.59 km of low voltage cables and 3707 pillar boxes. As discussed in earlier sections work is underway to improve the accuracy of LV data.

3.2.7.2 Customer Service Connection Assets

The identified customer service connection assets, excluding meters and relays, are summarised in Table 3.13.

CUSTOMER SERVICE CONNECTION ASSETS	
Description	**Number**
Overhead	20,610
Underground	3,929

TABLE 3.13: CUSTOMER SERVICE CONNECTION ASSETS

As discussed in earlier sections work is proposed to improve the accuracy of connection assets.

3.2.8 Overview of Secondary Assets such as Ripple Injection systems, SCADA and Telecommunications systems

3.2.8.1 Ripple Injection Systems

TLC operates two generations of ripple systems, one in the southern part of the network and a combination of new and old in the north. Both systems share the same controller, which is integrated into the Lester Abbey SCADA system. The Controller decides on the need to shed and restore load. Telegrams are generated at the plant controller level.

Table 3.14 lists the injection plants, frequencies, and injection voltages.

INJECTION PLANT LOCATION, TYPE, FREQUENCY AND VOLTAGE			
Location	**Plant Type**	**Frequency**	**Voltage**
Arohena	Landis Gyr Load Control	725Hz	11kV
Gadsby Road	Landis Gyr load control	725Hz	11kV
Maraetai	Landis Gyr load control	725Hz	11kV
Te Waireka	Landis Gyr load control	725Hz	11kV
Wairere	Landis Gyr load control	725Hz	11kV
Waitete	Landis Gyr load control	725Hz	11kV
Hangatiki	Landis Gyr	317Hz	33kV
Ohakune	Zellweger	317Hz	33kV
Ongarue	Zellweger	317Hz	33kV
National Park	Zellweger	317Hz	33kV
Tokaanu	Zellweger	317Hz	33kV
Whakamaru	Landis Gyr	317Hz	33kV

TABLE 3.14: INJECTION PLANT LOCATIONS, TYPES, FREQUENCIES AND VOLTAGES

The high frequency (725Hz) and relatively low power output of the 11kV Landis and Gyr legacy plants results in marginal to no signal being available for about 300 customers at Hangatiki and 500 customers at Marotiri. To overcome this problem, two new 317Hz 33kV plants were commissioned in 2010.

The 2009 and 2010 AMPs included an allowance to exchange and renew the 725 Hz relays with 317 Hz devices. This initiative has been substantially modified to TLC's intent to deploy advanced meters incorporating a relay across the entire network so that customer demands can be fully measured. It is expected that the advanced meter deployment will take at least five, possibly ten, years. The priorities for this deployment have however remained unchanged in that TLC needs to change frequency on the northern area to ensure all customers are receiving a reliable load control signal. The new units are physically enclosed in 40 foot containers to ensure they are modular and have adequate security.

The old Landis and Gyr plants will be able to be decommissioned once the advanced meters have been installed. TLC's future network vision is to find and develop more beneficial ways to run load control plants to improve network efficiency in conjunction with its demand based billing. i.e. The on-going development of the network to utilise smart or advanced network technologies. The stage currently being tested is the additional functionality required in the head end load control calculator to be able to receive local, zone substation and regional inputs and make various decisions based on this information.

3.2.8.2 SCADA Systems

The TLC network uses a Lester Abbey central control system and RTUs to automate approximately 35 zone substations, 12 load control plants and about 90 field devices and two investor owned generators. In addition it displays information from the grid exits, the Waikato River system and 4 other investor owned generation sites. In addition to operation of field devices, the equipment performs the central summation of system load and dispatch of load control signals. The amount of output from larger generators is also input into the system for the purpose of Transpower peak avoidance calculations and provision of information to the control room on the operating state of the network.

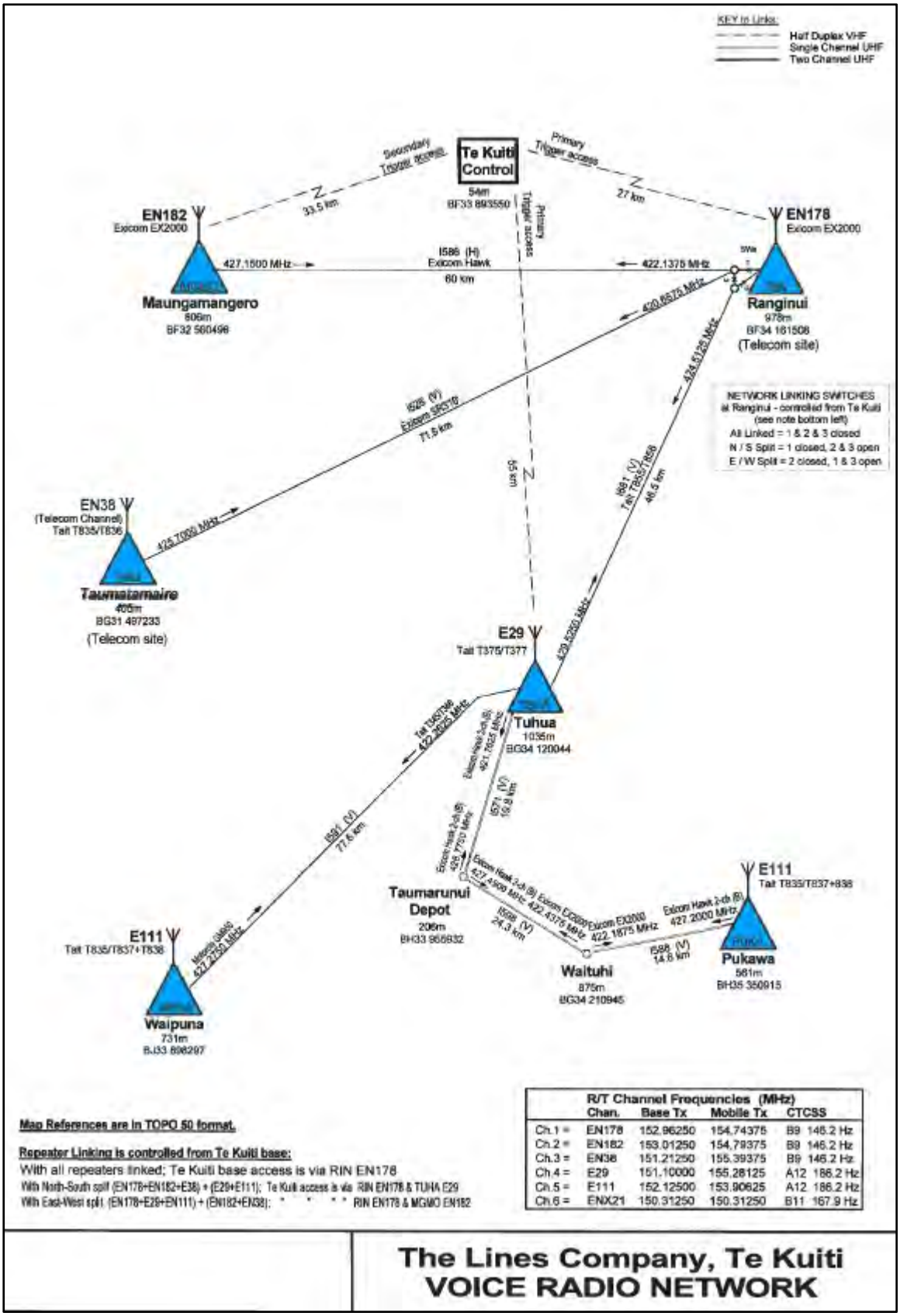
Specifications are currently being developed in conjunction with Abbey Systems for a more improved load control calculator as part of TLC's move towards a more advanced network.

One of the generator companies also uses the TLC SCADA system to communicate with its generation equipment and control a remote station. The system uses both a data UHF, voice VHF (radio) system and telephone line to communicate to field devices. The voice VHF system and the telephone line are only used in areas where it is difficult to get a data radio signal into. More detail on the radio communications system is included in the following sections.

3.2.8.3 Radio Communications Equipment

TLC operates a network of six E-Band (150 – 155 MHz), radio repeaters providing voice communication throughout the operational area.

Eight further repeaters divided across three sub communication networks provide a complimentary low speed (1200bps) SCADA transmission platform to access the 100 plus remote terminal units. Network diagrams for TLC's voice and SCADA networks are included in Figures 3.6a and 3.6b.



R/T Channel Frequencies (MHz)				
	Chan.	Base Tx	Mobile Tx	CTCSS
Ch.1 =	EN178	152.96250	154.74375	B9 146.2 Hz
Ch.2 =	EN182	153.01250	154.79375	B9 146.2 Hz
Ch.3 =	EN38	151.21250	155.39375	B9 146.2 Hz
Ch.4 =	E29	151.10000	155.28125	A12 186.2 Hz
Ch.5 =	E111	152.12500	153.90625	A12 186.2 Hz
Ch.6 =	ENX21	150.31250	150.31250	B11 167.9 Hz

FIGURE 3.6A: TLC VOICE RADIO NETWORK

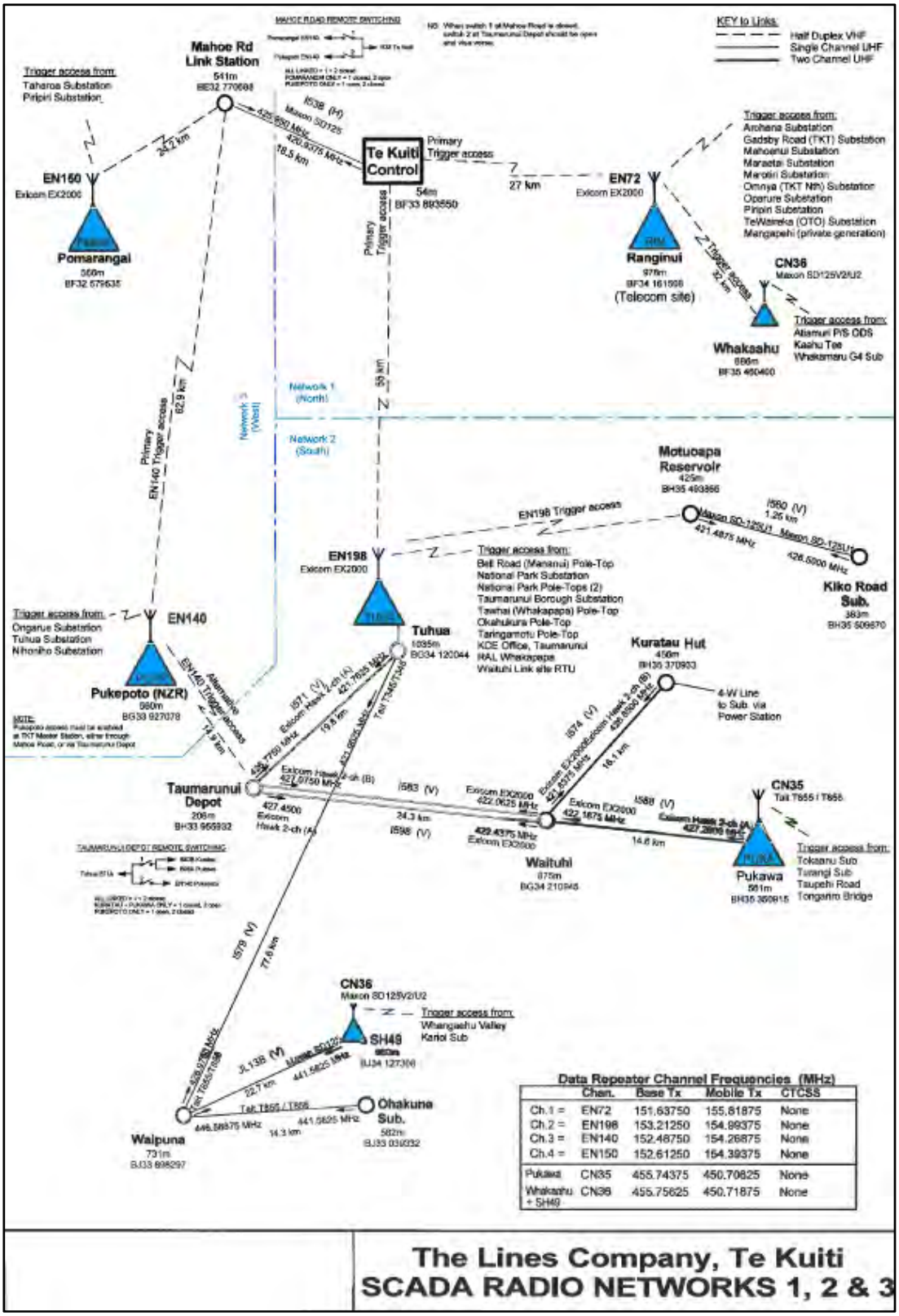


FIGURE 3.6B: TLC SCADA RADIO NETWORK

The communications system is low speed, but robust and relatively low cost. The installation of additional links to provide diversity is part of proposals for long-term development of the system. Changes to the radio spectrum license requirements will be a major driver in the on-going direction of the system. The plan is to systematically connect the voice then the data system to 12.5 kHz band width digital systems. Allowances included in Section 5 of this Plan will fund this development using TDMA technology.

3.2.8.4 Emergency Generator and Injection Transformer

The Lines Company owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11 kV network under emergency or shutdown conditions.

The unit consists of:

- 8-ton carrying capacity truck.
- 165 kVA, 400V generator.
- 150 kVA star-delta (Yd) 11 kV to 400 Volt transformer.
- NULEC 11 kV circuit breaker.
- Various connection leads and plugs; both 11 kV and 400 Volt.
- Road signage and emergency lighting.

The interconnection between the 11 kV circuit breaker is arranged so that further standard delta-star (Dy) connected transformers can be connected at the point between the circuit breaker and the star delta winding transformer. This allows larger generators to be connected and the Yd transformer to become a system protection earthing transformer. The machine has a communications system and the controller can remotely oversee and control the operation of the generator when it is connected to the network.

3.2.8.5 Mobile Capacitor Trailers

At the time of writing, two mobile capacitor 11 kV banks were being constructed. These each consist of:

- Controller.
- Circuit Breaker.
- 1 MVA r 11 kV capacitor bank.
- Trailer.
- Connection leads.
- Associated hazard control equipment.

These units will be used as an alternative network support tool to generators; i.e. add capacity to backup supplies without the need to bring in expensive generators.

3.2.9 Modular Substations

TLC has developed a modular, low cost way of establishing zone substations. The first substation was installed in 2006/07 and a further two were commissioned in 2008 and a fourth in 2010. These units consist of a 20-foot container, one 33/11 kV fixed tap transformer, two standard 11 kV line regulators, and an 11 kV line recloser. A 33 kV line recloser and a length of cable are used to connect the substation to the sub-transmission network. All equipment is installed in such a way that modern SCADA protocols can be used.

The concept has the following advantages:

- Environmentally acceptable. Resource consents are much more easily obtained than conventional construction.
- Modular and provides an alternative to large central substations.
- Easily transportable.
- Reduces and controls fault currents as compared to large centralised substations.
- Very secure.
- Suitable for industrial sites. Customers can more easily understand what capital investment their contributions are funding.
- Is ideal for supplying extra capacity into holiday areas or quickly moving to reinforce a legacy zone substation.
- Cost is 30 to 50% less than historical ways of constructing a zone substation.
- Commissioning and teething issues when being put into service are less than historical substations mostly due to the unit's simplicity.
- Lower operating costs and smaller land footprint.

The three initial units constructed have now been in service for 4 to 5 years and have operated better than expectations. They are a good solution to some of TLC's capacity growth strategy, i.e. they are modular and can be added in controlled increments.

3.2.10 Metering Assets

TLC, through a subsidiary company, owns the majority of customer meters and relays. It also owns interconnection metering assets at Whakamaru, Mokai, (commissioned June 2011), and Tangiwai (uncertified). About 40% of the domestic metering installations have two meters (controlled and uncontrolled). The remainder are a mixture of 2 phase and single meters.

As part of its demand billing initiative, TLC is deploying half hourly meters to domestic installations. These are read by both retailers (monthly or two monthly), and TLC (annual download of half hourly demands). These half hourly demands are reconciled with load control signals and customers' half hourly demands are used to calculate the annual demand component of their line charges.

The TLC owned relays are 80% of the modern programmable electronic type. The remainder are old and electro-mechanical relays. The channel segmentations of these relays is typically that of the legacy lines company load control systems, i.e. about 10 channels randomly deployed for water heater controls, 2 channels for street lighting, other channels for times controls and a few other channels mostly allocated for encouraging electrical energy usage programmes from the Electro Corp marketing strategies of the 1980's.

Looking forward, these channel layouts will be modified for the future to include more focus on demand billing, the fast load reduction frequency market and other activities involved with an advanced network.

3.3 Description of the Network Assets by Category including Age Profiles and Condition Assessment

3.3.1 Assets owned by the disclosing entity but installed at bulk supply points owned by others

TLC does have assets at bulk supply points owned by others. The assets at the supply points are as follows. The RAB values stated are approximate only.

3.3.1.1 Hangatiki

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
TLC equipment located at the Hangatiki grid exit point includes terminal spans into the site and a 5 MVA 33/11 kV zone substation. The zone substation includes transformer bunding and a disused historic Transpower substation building that houses indoor 11 kV switch gear, relays, SCADA, and batteries.
Cable into and out of the 11 kV switchgear is located on the site. A short length of fibre cable is also present to transport data from the Transpower equipment into the TLC RTU.
A new 317 Hz ripple injection plant housed in a 40 foot container was commissioned at the site in 2010. Two additional 33kV line reclosers were added as part of this project and the hazard control programme.

Age Profile
This equipment is, on average, 16 years old.

Regulatory Value (2010/11 Figures)
Regulatory Asset Base (RAB) $253,024

Condition of Assets
The condition of assets at the Hangatiki grid exit point is good. Recent DGA oil test results indicate that the 5 MVA transformer is in good serviceable condition. Equipment at the site has been reliable and provided acceptable levels of service.

3.3.1.2 Whakamaru

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The configuration at Whakamaru is unique and described in earlier sections of this Plan.

The assets at this site owned by TLC include:

1. Tertiary winding in a 220/110/33 kV transformer.
2. Protection associated with taking 33 kV supply from this transformer. This includes an earthing transformer.
3. SCADA and other communication equipment.
4. Electricity Commission rules compliant metering.
5. 33 kV circuit breaker.

This equipment is sited on Mighty River Power land adjacent to the Whakamaru Transpower substation.
A new 317 Hz ripple injection plant housed in a 40 foot container was commissioned at the site in 2010. An additional 33 kV recloser was added to supply this plant.

Age Profile
This equipment is, on average, 7 years old.

Regulatory Value (2010/11 Figures)
Regulatory Asset Base (RAB) $629,056

Condition of Assets
This equipment is in good condition. A major problem was experienced early on at this site with a bushing failure on a new Schneider "dog box" 33 kV circuit breaker. This is now being monitored.

3.3.1.3 Atiamuri

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The configuration at Atiamuri is unique and described in earlier sections of this Plan.
The assets at this site owned by TLC include:

1. 33 kV circuit breaker, protection, and controls.
2. Site development.
3. 10 MVA step up 11 kV to 33 kV transformer.
4. 11 kV cabling.
5. RTU and other associated equipment.

This equipment is sited on Mighty River Power land and leased to Transpower from Mighty River Power.

Age Profile
This equipment is, on average, 19 years old.

Regulatory Value (2010/11 Figures)
Regulatory Asset Base (RAB) $780,222

Condition of Assets
Condition of assets at this site is good.

3.3.1.4 Ongarue

Voltage Level
33 kV

Description and Quantity of Assets
The equipment is located at the Transpower grid exit point and consists of termination spans, bypassing switchgear, and a ripple injection plant and site development including security fencing.
The equipment is located on Transpower land.

Age Profile
This equipment is, on average, 17 years old.

Regulatory Value (2010/11 Figures)
Regulatory Asset Base (RAB) $ 261,071

Condition of Assets
The equipment on this site is in average to good condition. No reliability problems have been experienced. TLC load control equipment and radios were relocated out of the Transpower building and renewed in 2007 to overcome complex access requirements. This equipment is now located in a container adjacent to the Transpower site.

3.3.1.5 Tokaanu

Voltage Level
33 kV

Description and Quantity of Assets
The equipment located at the Transpower and Genesis Energy Tokaanu site includes a load control plant and 33 kV switchgear.

Age Profile
This equipment is, on average, 15 years old.

Regulatory Value (2010/11 Figures)
Regulatory Asset Base (RAB) $ 310,470

Condition of Assets
Assets at this site are in good condition. There have been no operational issues from the site. There is however, a low risk/priority concern about the closeness of 33 kV jumper connections to the fence in the ripple control inductor and capacitor structure.

3.3.1.6 National Park

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The assets at the National Park Transpower grid exit include a ripple injection plant and a 33/11 kV 3 MVA substation.
Associated equipment includes SCADA, structures, and site development.

Age Profile
This equipment is, on average, 17 years old.

Regulatory Value (2009/10 Figures)
Regulatory Asset Base (RAB) $ 255,554

Condition of Assets
Assets are in serviceable condition. A relocation of the zone substation transformer is included in this Plan (1967 transformer with high winding moisture content). The protection arrangement and configuration of circuit breakers at the site is less than ideal. (Addressed in the plan.)
There are also hazard control issues with the transformer and ripple injection enclosures. The site has no oil containment and inadequate earthquake constraints. Overall the site falls short of today's hazard control, environmental and operating expectations. An allowance for addressing hazard, environmental and operating issues at this site has been included in forward renewal projections.

3.3.2 Sub-transmission Network including power transformers

3.3.2.1 Sub-transmission lines; voltages, description, value, age and condition profiles

Table 3.15 lists the voltage, description and quantity, value and condition of Sub-transmission line assets.

33 KV SUB-TRANSMISSION ASSETS - DESCRIPTION, VALUE, AGE AND CONDITION				
Description	**Purpose**	**RAB**	**Average Age (yrs)**	**Condition**
Gadsby / Wairere 33 Length 32.8km	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	1,569,687	28	Well-designed line that over the last few years has been partly renewed. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged components failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Gadsby Rd 33 Length 17.4 km	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	790,424	35	Well-designed line that over the last few years has been partly renewed. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged components failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Lake Taupo 33 Length 32.7 km	Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations.	1,359,429	43	Line has almost been rebuilt over last 5 to 8 years. It was originally unable to withstand the fault current capacity of the Tokaanu Grid Exit. Earlier parts of the rebuild were completed to a low cost design and do not have a high inherent strength. The river crossing over the sensitive Tongariro River is of less than ideal design and is a risk to trout fishermen who use conductive fishing lines on the Tongariro River. Estimates to address this issue have been included in future plans.
Mahoenui 33 Length 22.6 km	Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. DG resource exists in the area is under investigation.	1,016,285	29	Upgraded in 1994 from 22 kV. Lighter type of construction than the lines described above. Main problems over recent years have been trees, insulator failure due to fertiliser build up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.

33 KV SUB-TRANSMISSION ASSETS - DESCRIPTION, VALUE, AGE AND CONDITION				
Description	**Purpose**	**RAB**	**Average Age (yrs)**	**Condition**
National Park / Kuratau 33 Length 57.2 km	Interconnecting line between the National Park GXP and Kuratau marshalling site. Normal load on line is the Whakapapa ski field and Central Plateau rural area including supply to the Whanganui diversion race controls.	748,835	54	Line has been split into two sections. The section between National Park and the Tawhai Substation has been renewed. Every 5th pole and all insulators have been replaced. The purpose was to increase the strength. This section of line supplies the Chateau and Whakapapa ski fields. (The lack of design strength was demonstrated when this project was underway and a lineman ended up with a broken leg after riding a pole to the ground.) The section between Tawhai and Kuratau Substation is a secondary link and has been patched at known trouble spots. This line is under ideal design strength and trips whenever wind speeds exceed about 60km/hr.
National Park 33 Length 0.04 km	Short length of spur line connecting National Park GXP to zone substation.	64,905	32	Short length of line at GXP.
Nihoniho 33 Length 14.6 km	Spur line connecting Ongarue GXP to Nihoniho zone substation.	858,997	34	Aged low strength line that has been partly renewed. Low cost design that has been patched up. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Ongarue / Taumarunui 33 Length 18.6 km	Main line supplying Taumarunui from the Ongarue GXP.	1,232,134	27	Low strength line that was patched, renewed and strengthened about 15 years ago. As part of next 15-year cycle needs the strength increased further. Line mostly in very steep, inaccessible hill country. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Taharoa A 33 Length 53.1 km	Supply to iron sand extraction at Taharoa and future DG sites (West Coast Wind and Hydro) (Customer requested and funded. Some local rural supply also.	2,463,080	37	Well Designed Line that over the last few years has been extensively renewed for parts of its length. Further renewal of poles and hardware is needed . Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings. Emergency renewal is included in 2009/10 programme. Further renewal will have to be funded by customer if they wish on improved level of reliability.
Taharoa B 33 Length 45.9 km	Supply to iron sand extraction Taharoa and future DG sites. (West Coast Wind and Hydro - Customer requested and funded). Some local rural supply also.	2,414,937	30	Well-designed line that over the last few years has been extensively renewed for part of length. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.

33 KV SUB-TRANSMISSION ASSETS - DESCRIPTION, VALUE, AGE AND CONDITION				
Description	**Purpose**	**RAB**	**Average Age (yrs)**	**Condition**
Taumarunui / Kuratau 33 Length 38.0 km	Interconnecting line between the Ongarue GXP and the Kuratau marshalling site. Normally loaded with output of Kuratau area DG back into the Ongarue GXP. If Kuratau DG did not exist or was not paying a fair portion of this line, options for continuing renewal, maintenance and ownership will need further evaluation.	728,761	51	Line has adequate size conductor ,but poles well under strength for today's environment. Ideally all poles need replacing to increase line strength. As a stopgap measure it is proposed to replace every 5th pole as part of on-going programmes to increase line strength. The poles are also very short and the line has a number of ground to conductor clearance issues.
Te Kawa St 33 Length 12.0 km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	610,255	38	Well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Te Waireka Rd 33 Length 8.2 km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	245,946	40	Well designed line that over the last few years has been extensively renewed for most of length. Main problems over recent year have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings. Has been strengthened for part of length to overcome fireball problems from conjoint 11 kV circuits below.
Tokaanu / Kuratau 33 Length 16.0 km	Interconnecting line between the Tokaanu GXP and Kuratau marshalling site. Normally supplies Kuratau zone sub and is a backup for the connection of the Kuratau area DG to the grid. Also used to back up National Park and Ongarue.	855,939	45	Line has adequate size conductor but poles well under strength for today's environment. As a stopgap measure it is proposed to replace every 5th pole as part of on-going programmes to increase line strength. The poles are also very short and the line has a number of ground to conductor clearance issues.
Tuhua 33 Length 0.1 km	Few metres of spur line connecting Ongarue GXP to Tuhua zone substation.	14,799	32	Short length of line that has been partly renewed. There have been no recorded failures on this short section of line.
Turangi 33 Length 2.9 km	Spur line connecting Tokaanu GXP to the Turangi zone substation.	58,802	48	Line has recently been renewed. Includes a number of iron rails. Old but in renewed condition.

33 KV SUB-TRANSMISSION ASSETS - DESCRIPTION, VALUE, AGE AND CONDITION				
Description	**Purpose**	**RAB**	**Average Age (yrs)**	**Condition**
Waitete 33 Length 10.8 km	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	900,282	27	Well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings to overcome the fertiliser problem.
Whakamaru 33 Length 112.4 km	Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu and Marotiri zone substations.	3,000,754	39	Originally constructed as a 50kV transmission line. Purchased by TLC in 2002 and has since been operated at 33kV. As part of the conversion process, aged conductor where changed and small 33kV insulators fitted.

TABLE 3.15: VOLTAGE, DESCRIPTION AND QUANTITY, AGE, VALUE AND CONDITION OF 33 KV SUB-TRANSMISSION ASSETS

An indication of age profiles of the 33 kV lines is illustrated in summary in Figure 3.6.

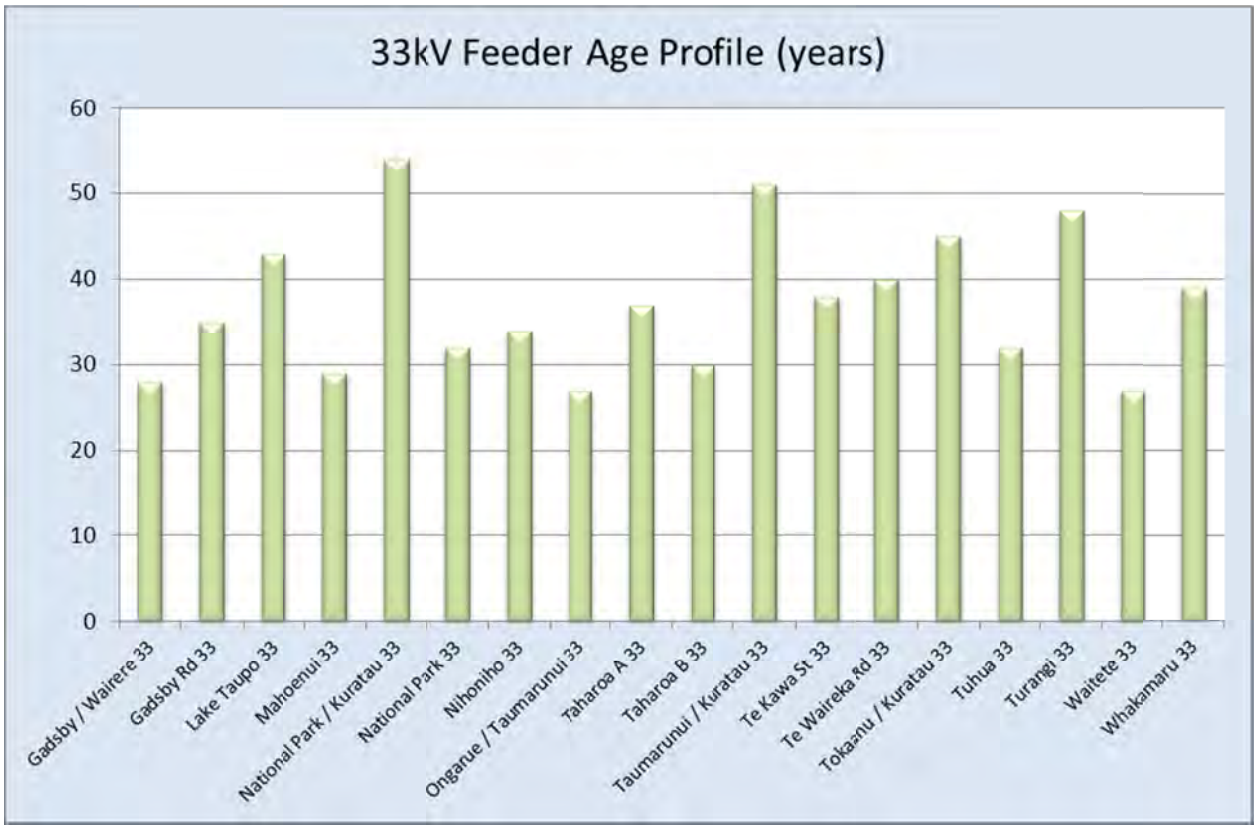


FIGURE 3.6: OVERALL AGE PROFILE OF 33 KV SUB-TRANSMISSION LINES

The effect of the present renewal strategies on this profile will be to bunch the age profiles and hold them in the 20 to 40 year range. This will ensure there is no shock to replace the entire assets over and above what is presented in this Plan provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur. The renewal programme will result in continuous asset technology upgrade, i.e. the latest technology and materials etc. will be used for renewals.

The systemic issues that lead to premature replacement of 33 kV assets or parts of these assets include:

1. *Insulator failure*

   The most common failure mode for 33 kV lines in the TLC network is insulator corona discharge to flashover, due mainly to fertiliser build-up. This problem is particularly acute with the smaller insulators equivalent to the NZI3370W that industry accepted as a standard insulator about 20 to 30 years ago.

2. *Flashover due to magpies on cross arms*

   Similar to 1 above with the corona to flashover being advanced when a magpie is in parallel with the insulator. Again, this problem is worst on lines constructed or upgraded in the last 20 years where smaller insulators have been used.

3. *Failure of Air Break Switches*

   A series of problems have arisen in recent times with 1980s manufactured 33 kV NZI 4-bolt insulators on 33 kV switches. These are a multi-piece insulator that, after about 20 years' service, are failing due to expansion of the cement that holds them together.

4. *Lightning arrestors*

   Earlier model distribution class arrestors are prone to failure and create difficult to find earth faults.

5. *Trees*

   All overhead lines are prone to tree faults. Even though considerable effort has been put into clearing 33 kV lines, from time to time an event still occurs.

6. *Slips*

   Slips are common in the clay hills of the King Country. These slips often dislodge poles and cause faults, or on occasion bring trees into the lines.

7. *Pole and cross arm failure*

   The lines inspection and pole-testing programme has substantially reduced these events but from time to time, they still occur.

8. *Insulator wire ties*

   Failures of wire ties that hold wires on insulators occur from time to time, especially in areas exposed to high winds and snow or vibration.

9. *Wire clashes*

   Wire clashing to conductor failure occurs from time to time. The cause of this is usually related to the original line designs. Due to the rugged country, conductor spacing's often end up too close and clash during high wind events or during the passage of fault currents.

Figure 3.7 illustrates corona discharge typical of that caused by a fertiliser build-up on a 33 kV insulator.

FIGURE 3.7: EXAMPLE OF CORONA DISCHARGE ON FERTILISER POLLUTED 33 KV INSULATOR

3.3.2.2 Sub-transmission Substations excluding power transformers

Table 3.16 lists the voltage, description and quantity, value (Regulatory), and condition of sub-transmission zone substations.

SUB-TRANSMISSION ZONE SUBSTATIONS – DESCRIPTION, AGE, VALUE AND CONDITION				
Zone Substation	**Description**	**Age of Substation**	**RAB excludes Tx**	**Condition**
Arohena	Single unit site ex Transpower point of supply. Very limited 11kv backup at light loads.	25	403,119	Maintained ex Transpower site. Has bunding and oil separation.
Awamate	Modular substation with backup from Turangi at light loads.	3	241,979	New asset. Performing better than expectations.
Borough	Two unit site able to supply full load short term on one unit. Two supplies available for 33kV. Medium load backup at 11 kV with some transfer and embedded generation.	21	820,069	Average condition. Bunded with manual outlet valve. Site can flood. Single 11kV busbar. 33kV protection and switchgear needs reviewing.
Gadsby Road	Single unit site on north side of Te Kuiti. Two alternative 33 kV supplies running as closed ring. Medium load 11 kV alternatives.	34	96,504	Well build site. Reasonable condition. Has bunding and oil separation. Does not have earthquake constraints.
Hangatiki	Single unit site at Transpower point of supply. Two alternatives for 33kV running as closed ring with very short spur to sub bus. 11kV backup at medium loads.	16	325,638	Well built site. Reasonable condition. Has bunding but no oil separation.
Kaahu Tee	Modular substation with backup from Marotiri and Maraetai.	2	196,828	New Asset - performing better than expectations.
Kiko Road	Single unit site. Single 33 kV line supply. No 11 kV alternatives.	9	229,620	New condition . Bunded with automatic Aqua Sentry Device.
Kuratau 33 (Switchyard)	Switching site close to Kuratau Village Substation.	30	190,316.9	Switching site with various structures and switchgear. Some of the switchgear has been renewed. Remainder of old equipment included in renewal programmes.
Kuratau	Single unit site. Three 33kV supplies. No 11kV alternative. Local embedded generation if water available.	10	572,517.2	New condition. Bunded with manual outlet valve.
Mahoenui	Single unit. Single 33 kV line. Backup at light loads.	24	162,993	Average TLC zone site. Reasonable condition. Has bunding and separation. Has older type 11kV breaker that does large number of operations.
Manunui	Single unit site. Two 33 kV supplies available. Light to medium load 11 kV backup.	25	213,957	Average condition. Bunded with in ground separator. Improvements included in plan.

SUB-TRANSMISSION ZONE SUBSTATIONS – DESCRIPTION, AGE, VALUE AND CONDITION				
Zone Substation	**Description**	**Age of Substation**	**RAB excludes Tx**	**Condition**
Maraetai	Single unit ex Transpower point of supply. Single 33 kV line. 11 kV backup at medium loads. Modification made to 24VDC actuators supplied from the 2 x 24 VDC cells.	23	303,122	Well maintained ex Transpower site. Good condition site. Has oil separation and bunding. Has aging incoming 33 kV breaker.
Marotiri	Single unit ex Transpower point of supply. Single 33 kV line 11kV backup at light loads.	21	233,663	Well maintained ex Transpower site. Good condition site. Has oil separation and bunding. Loading is at full or greater than rating.
National Park	Single unit site. Two 33kV supplies. Medium load 11kV backup.	35	75,241	Poor condition. No bunding or oil separation. Improvements are included in the plan.
Nihoniho	Single unit site. Single 33kV supply. Light to medium load 11kV backup.	35	72,038	Poor condition. No bunding or oil separation. Has hazard constraint. Improvements included in plan.
Oparure	Single unit mostly supplying specific customer. (Limestone processing). Single 33kV line spurred off closed ring.	17	168,732	Good condition. Operating in harsh environment at Quarry. No bunding or separation.
Otukou	Single unit site. Two 33/11kV supplies. No 11kV backup.	12	141,962	Average condition. No bunding or oil separation. Improvements included in plan.
Piripiri	Transformer failed in 2010. Load in area picked up by Te Anga substation.	30	140,030	Now used as a switching station.
Taharoa	Three units supplying iron sand extraction and local load. Two 33kV lines operating as closed ring.	33	513,746	Poor condition. Operating in harsh environment on beach. No bunding or oil separation. Has a metering compliance and hazard issues. 15 MVA capacity at site.
Tawhai	Single unit site. Two 33kV supplies. Light to medium 11kV backup.	34	168,847	Average condition. No bunding or oil separation. Improvements included in plan.
Te Anga	Modular substation with backup from Taharoa.	1	450,000	New asset performing to expectations.
Te Waireka	Two unit site with one unit able to carry full load. Two 33kV lines operating as closed ring. Medium load 11kV backup available.	25	384,054	Average to good condition. Oil separation and bunding. Single busbar. Aging oil filled switchgear. Feeder loadings are high. Protection old and needs review. Diversity for busbar arrangement included in plan.
Tokaanu Village	Single unit site. Single 33kV line. No 11kV backup.	14	155,181	Good condition. Improvements included in plan.
Tuhua	Single unit site. Single 33kV line close to Transpower point of supply. Light to medium 11kV backup.	31	71,211	Poor condition. No bunding or oil separation. Has hazard constraint. Improvements included in plan.

SUB-TRANSMISSION ZONE SUBSTATIONS – DESCRIPTION, AGE, VALUE AND CONDITION				
Zone Substation	**Description**	**Age of Substation**	**RAB excludes Tx**	**Condition**
Turangi	Two unit site. Single 33kV line. No 11kV backup.	17	681,648	Poor condition. Protection needs review. Hazards need addressing. Improvements included in plan.
Waiotaka	Modular substation with backup from Turangi.	5	212,100	New asset - performing better than expectations.
Wairere	Two unit site in conjunction with embedded generation. Limited 11kV backup. Supply will island.	32	606,663	Average condition. Bunded with manual outlet valve. Protection and 33kV bus arrangement needs reviewing.
Waitete	Three unit site. Able to supply full load with some 11 kV transfer and embedded generation. Two 33kV lines running in closed ring.	37	487,677	Good condition. Bunded with manual outlet valve. Has a security hazard to be minimized issue. Improvements included in the plan.

TABLE 3.16: VOLTAGE, DESCRIPTION AND QUANTITY, VALUE AND CONDITION OF SUB-TRANSMISSION ZONE SUBSTATIONS

An indication of the age profiles of zone substations are given in Figure 3.8.

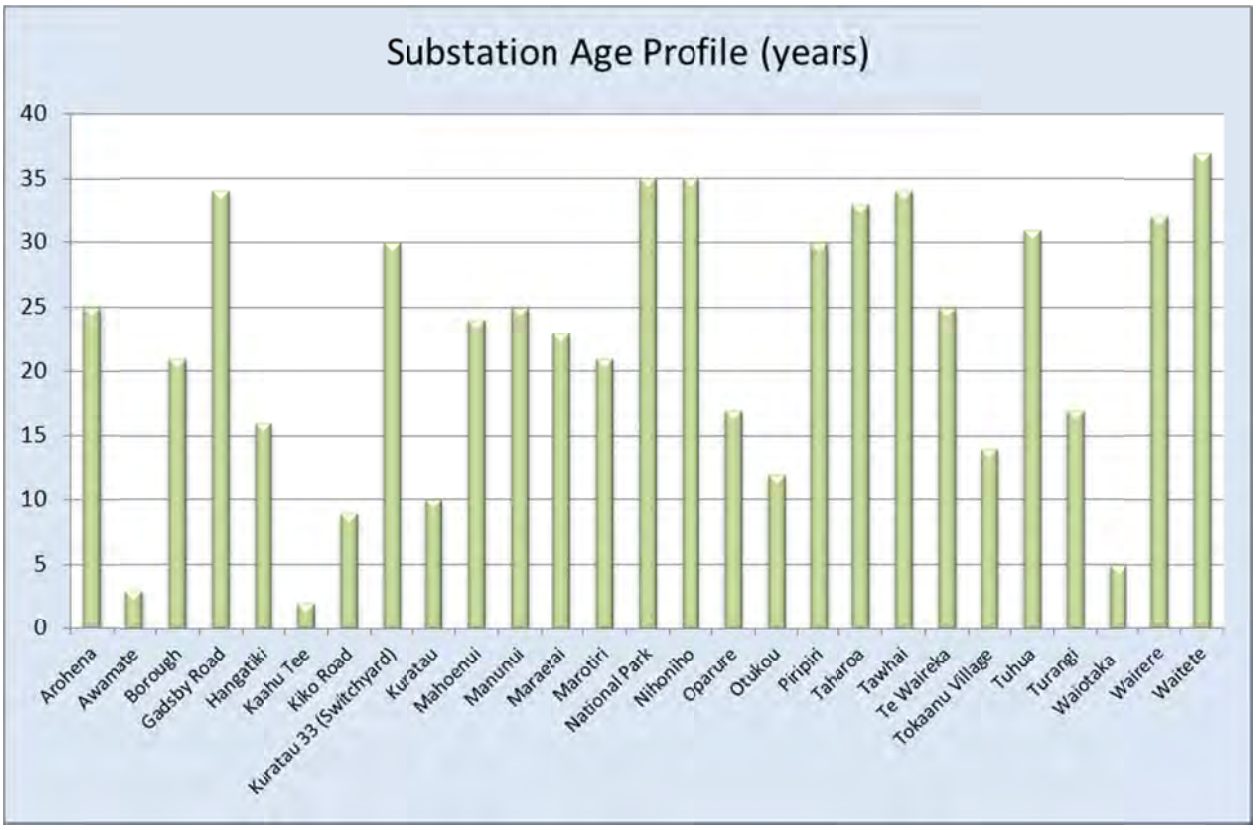


FIGURE 3.8: AGE PROFILE OF ZONE SUBSTATIONS

It is expected that present development and renewal plans and strategies will see the age profiles of zone substations remain relatively static. New distributed modular substations will provide backup and reduce loading on sites with old equipment or single bus bar arrangements. This will ensure there is no shock to replace the entire assets provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur. The renewal programme will result in continuous asset technology upgrade, i.e. the latest technology and materials etc. will be used for renewals.

The Plan allows for switchgear and control systems to be renewed on a continual basis. The systemic issues that lead to the premature replacement of zone substation assets or parts of these assets include:

1. *Air Break Switches*

   As outlined in line failures, there is a batch of switches with insulators manufactured by New Zealand Insulators in the 1980s that from time to time crack and fall apart.

2. *Control* equipment

   Voltage control relays and protection relays tend to fail at the rate of two to three per year. When this occurs, units are replaced with modern equivalents.

3. *Fault* Throwers

   Unreliable, and often fall apart when they are reset. The improvement and cost of circuit breaker technology along with increasing fault levels means these devices are unreliable and creating hazards.

4. *Batteries*

   A number of batteries and battery chargers have failed in the past. The number of failures has reduced now that a renewal programme is in place.

3.3.2.3 Sub-transmission Power Transformers

Table 3.17 lists the voltage levels, description and quantity, regulatory value age profiles and condition of zone substation power transformer assets.

ZONE SUBSTATION POWER TRANSFORMERS – DESCRIPTION, AGE, VALUE AND CONDITION								
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**RAB**	**Condition**
Arohena	33kV / 11kV	3.0 MVA	211T1	Alstom Transformer Division	Associated Tap Changer	9 yrs (2002)	280,385	2010 oil test result show the condition of the unit is acceptable.
Awamate	33kV / 11kV	2.0 MVA	T4274	ETEL Limited	Line Regulator	3 yrs (2008)	102,962	New Unit. 2010 oil test result show the condition of the unit is acceptable.
Borough	33kV / 11kV	5.0 MVA	508T1	Bonar Long & Co Ltd	Ferranti	46 yrs (1965)	-	2008 Oil refurbished. Unit is being refurbished at time of writing.
Borough	33kV / 11kV	5.0 MVA	508T2	Bonar Long & Co Ltd	Ferranti	46 yrs (1965)	-	Oil test in 2004 show that half-life maintenance is required. 2008 oil refurbished. Feb 2010 half life refurbishment was carried out. Sep 2010 oil test result show the condition of the unit is acceptable.
Gadsby Road	33kV / 11kV	5.0 MVA	205T6	Turnbull & Jones	Hawker Siddeley	5 yrs (2006)	151,550	Transformer rebuilt in 2005 after a major failure. 11kV windings replaced. Unit totally stripped and dried. 2010 oil test result show the condition of the unit is acceptable.
Hangatiki	33kV / 11kV	5.0 MVA	204T1	Tyree	Associated Tap Changer	19 yrs (1992)	233,890	2010 oil test result show the condition of the unit is acceptable for a transformer of this age.
Kaahu Te	33kV / 11kV	2.4 MVA	216T1	ETEL Limited	Line Regulator	2 yrs (2009)	299,754	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Kiko Road	33kV / 11kV	3.0 MVA	518T1	Alstom Transformer Division	Associated Tap Changer	10 yrs (2001)	273,864	2010 oil test result show the condition of the unit is acceptable.
Kuratau	33kV / 11kV	3.0 MVA	509T1	Hawker Siddeley	Hawker Siddeley	56 yrs (1955)	-	Transformer relocated from Taharoa. Condition under question. Tank has been refurbished and oil reclaimed Transformer is being monitored closely. Emergency back put on site in case of failure.

ZONE SUBSTATION POWER TRANSFORMERS – DESCRIPTION, AGE, VALUE AND CONDITION								
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**RAB**	**Condition**
Kuratau	33kV / 11kV	1.5 MVA	509T2	Turnbull & Jones	Fuller	2 yrs (2009)	299,754	2010 oil test result show the condition of the unit is marginally acceptable. Oil reclamation required. Allowances for this work have been included in plan period estimates.
Mahoenui	33kV / 11kV	3.0 MVA	209T1	Brush	Brush	45 yrs (1966)	45,644	2003 Oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Manunui	33kV / 11kV	5.0 MVA	510T1	Bonar Long & Co Ltd	Ferranti	46 yrs (1965)	-	Oil refurbished 2003. Acceptable operation at this time . Unit is due for half-life refurbishment. Allowances for this work have been included in plan period estimates.
Maraetai	33kV / 11kV	5.0 MVA	210T11	Alstom	Associated Tap Changer	10 yrs (2001)	297,679	2010 oil test result show the condition of the unit is acceptable.
Marotiri	33kV / 11kV	3.0 MVA	212T1	Alstom	Associated Tap Changer	10 yrs (2001)	273,864	2010 oil test result show the condition of the unit is acceptable.
National Park	33kV / 11kV	3.0 MVA	501T1	Bonar Long & Co Ltd	Associated Electrical Industries (AEI)	44 yrs (1967)	52,165	Oil test marginally acceptable. Unit is coming due for half-life refurbishment. Allowances for this work have been included in plan period estimates.
Nihoniho	33kV / 11kV	1.5 MVA	503T1	ETEL Limited	Line Regulator	1 yrs (2010)	2,111	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Oparure	33kV / 11kV	3.0 MVA	208T1	ABB Transformers	ABB	17 yrs (1994)	228,220	2010 oil test result show the condition of the unit is acceptable.
Otukou	33kV / 11kV	0.5 MVA	512T1	Turnbull & Jones	Line Regulator	1 yr (2010)	25,442	Acceptable condition
Taharoa	33kV / 11kV	5.0 MVA	201T8	Turnbull & Jones	Associated Tap Changer	32 yrs (1979)	141,752	2004 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Taharoa	33kV / 11kV	5.0 MVA	201T9	Turnbull & Jones	Fuller Electrical	40 yrs (1971)	74,845	2010 oil test result show the condition of the unit is acceptable. Relocated during 2008 from Kuratau.
Taharoa	33kV / 11kV	5.0 MVA	201T10	Turnbull & Jones	Associated Tap Changer	40 yrs (1971)	85,051	2005 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.

ZONE SUBSTATION POWER TRANSFORMERS – DESCRIPTION, AGE, VALUE AND CONDITION								
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**RAB**	**Condition**
Tawhai	33kV / 11kV	5.0 MVA	513T1	Bonar Long & Co Ltd	Ferranti	45 yrs (1966)	49,613	Oil tests are marginally acceptable. Transformer is due for half-life refurbishment. Allowances for this work have been included in the plan period estimates .
Te Anga	33kV / 11kV	3.0 MVA	T3326	ETEL Limited	Line Regulator	1 yr (2010)	44,978	New transformer
Te Waireka	33kV / 11kV	10.0 MVA	203T3	Alstom Transformer Division	Fuller Electrical	10 yrs (2001)	428,657	This transformer failed during 2005 due to a poorly made crimp connection on the 33kv delta winding jumpers. The unit had to be detanked, all the connections repaired in the unit, dried and retanked. 2010 oil test result show the condition of the unit is acceptable.
Te Waireka	33kV / 11kV	10.0 MVA	203T4	Alstom Transformer Division	ABB	15 yrs (1996)	377,627	2010 oil test result show the condition of the unit is acceptable.
Tokaanu Village	33kV / 11kV	1.3 MVA	507T1	ABB Transformers	Fuller Electrical	15 yrs (1996)	209,793	2010 oil test result show the condition of the unit is acceptable.
Tuhua	33kV / 11kV	1.5 MVA	502T1	Bonar Long & Co Ltd	Line Regulator	49 yrs (1962)	-	2004 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Turangi	33kV / 11kV	5.0 MVA	505T1	English Electric	Fuller Electrical	50 yrs (1961)	-	Oil test marginally acceptable. Half life maintenance of transformer is due and included in plan.
Turangi	33kV / 11kV	5.0 MVA	505T3	English Electric	Fuller Electrical	47 yrs (1964)	-	2010 oil test result show the condition of the unit is acceptable.
Waiotaka	33kV / 11kV	1.5 MVA	511T1	ETEL Limited	Line Regulator	5 yrs (2006)	104,330	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Wairere	33kV / 11kV	2.5 MVA	207T11	Metro-Vickers	Associated Tap Changer	31 yrs (1980)	130,979	2010 oil test result show the condition of the unit is acceptable.
Wairere	33kV / 11kV	2.5 MVA	207T12	Metro-Vickers	Associated Tap Changer	31 yrs (1980)	130,979	2010 oil test result show the condition of the unit is acceptable.
Waitete	33kV / 11kV	5.0 MVA	206T1	English Electric	Fuller Electrical	50 yrs (1961)	-	2003 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.

ZONE SUBSTATION POWER TRANSFORMERS – DESCRIPTION, AGE, VALUE AND CONDITION								
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**RAB**	**Condition**
Waitete	33kV / 11kV	5.0 MVA	206T2	English Electric	Fuller Electrical	50 yrs (1961)	-	2003 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Waitete	33kV / 11kV	5.0 MVA	206T3	Metro-Vickers	Metro-Vickers	56 yrs (1955)	-	Spare network 5 MVA transformer. Was temporarily put into Waitete as part of 2007 programme. Configuration allows easy removal and transportation to another site in an emergency. 2010 oil test result show the condition of the unit is acceptable.

TABLE 3.17: ZONE SUBSTATION TRANSFORMERS: LOCATION, AGE, AND CONDITION

Figure 3.9 summarises the age profile of TLC's zone substation power transformers.

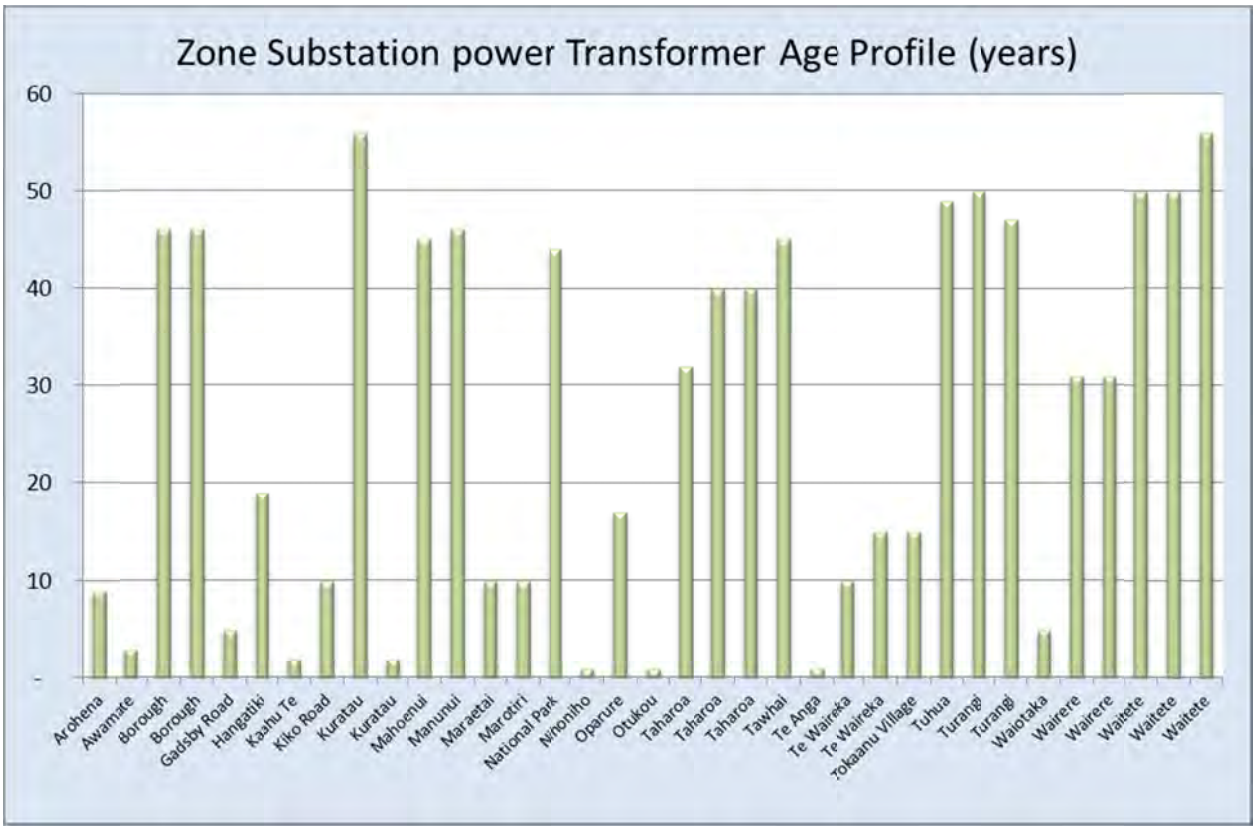


FIGURE 3.9: AGE PROFILES OF ZONE SUBSTATION POWER TRANSFORMERS

It is expected that the age profile of zone substation transformers will stay spread with a flow of new modular units into the lower age section. Older units as listed in Table 3.17 will be refurbished to extend their life. (Allowances are included in Plan estimates.)

Experience has shown that most transformers fail after the passage of fault current. Windings and packing become loose and wet with age. Fault currents cause movement and localised heating. Movement can deform windings and localised heating can result in ionisation of moisture in windings. If the older solid units are serviced, experience shows that they will perform very well and will likely give continuing good service. This is, however, subject to other variables such as tank, paper, tap-changer, and other components' condition.

A relatively new 10 MVA T3 unit at Te Waireka failed due to a poor connection in 2003. It was likely that this connection was substandard since manufacture. Areva, the manufacturer of this product, was not prepared to fund any of the repairs.

Changes over the last few years have meant there are now effectively two 5 MVA units that can be re-deployed in an emergency. (One each from Waitete and Turangi.) Refurbishment of the older units and deployment of a number of new modular substations will mean that no sudden shock to replace a number of units will likely result.

A number of the newer ETEL units have had oil tests come back that show higher than ideal hydrogen levels. This problem has been taken up with the suppliers; and a specific problem with oil reacting with galvanising in the tank has been identified. This issue is currently being worked through.

3.3.2.4 Sub-transmission switchgear

Table 3.18 lists the voltage levels, description, quantity, value and condition of 33 kV switchgear assets.

33 kV SWITCHGEAR ASSETS – DESCRIPTION, QUANTITY, VALUE AND CONDITION			
Description	**Qty**	**RAB**	**Note**
Air Break Switches	101	253,515	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Circuit Breakers	40	857,094	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Fault Throwers	11	38,544	These devices are in poor condition and the Plan includes programmes to replace them with circuit breakers.
Fused Dropouts (Sets)	7	49,736	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Reclosers	7	322,188	New condition
Solid Links	28	274,561	Ages and condition vary. Switches are renewed when they are no longer serviceable.

TABLE 3.18: QUANTITY VALUE AND CONDITION OF 33 KV SWITCHGEAR ASSETS

Figure 3.10 gives an indication of the age profile of sub-transmission switchgear.

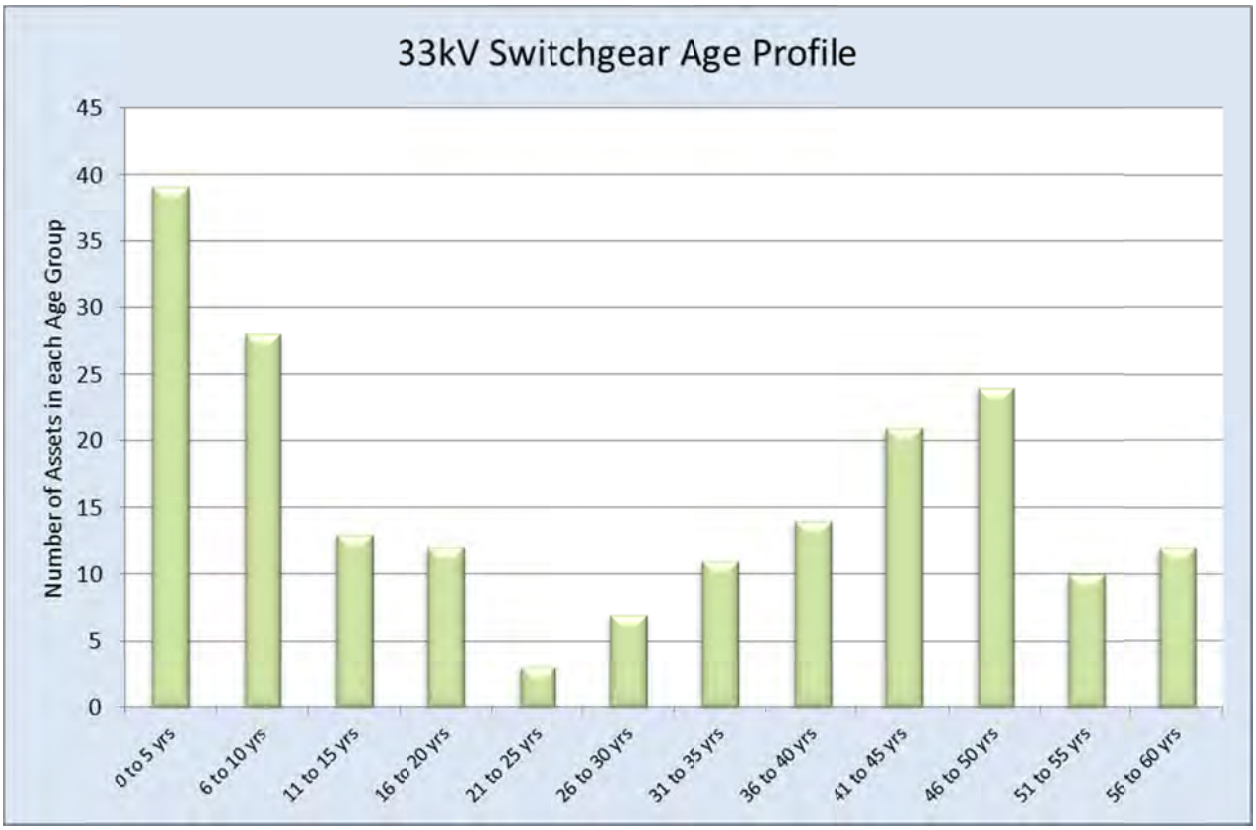


FIGURE 3.10: AGE PROFILE OF SUB-TRANSMISSION SWITCHGEAR

The age profiles of 33 kV switchgear has improved and will continue to follow the trend in figure 3.10 during the planning period with new units replacing the older ones as part of the renewal programme.

The renewal programme will also result in a continuous asset technology upgrade. Modern, low maintenance equipment with electronic controls will improve the overall asset performance and lower the maintenance costs of switchgear over time.

The condition of sub-transmission switchgear varies widely from relatively modern equipment to very old items. Generally, equipment operates satisfactorily and any that is found to be unserviceable is renewed.

The main causes of premature failure of these assets have been over voltages, mechanical linkage problems, and corrosion in extreme environments. A number of early electronic and electro-mechanical relays controlling this equipment have failed. Over voltages are likely to have been caused by lightning and switching surges.

3.3.3 Distribution Network (11 kV) including Distribution Transformers

3.3.3.1 Distribution feeders

The voltage levels, description of quantity of assets, age profiles, values of assets and a discussion of the condition of assets for distribution feeders are listed in table 3.19.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Aria	Aria rural area	77.9	35	2,443,973	261	Average condition rural feeder. Constructed predominantly on 10/2KN concrete poles. Problems have been experienced in recent times with low creepage distances 1950's insulators discharging to pin and cracking causing auto-recloses when it rains.
Benneydale	South east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats	133.8	40	3,356,710	467	Long feeder with rural, industrial and distributed generation connections. Has four regulators in series being run to the maximum. Has been substantially renewed. Travels through moderate hill country and includes many long spans with some close conductor phase spacings.
Caves	Waitomo village and rural area to the west.	65.4	36	1,577,655	313	Rebuilt to Waitomo Caves. Beyond this there are long spans with light low strength conductor that is prone to failure. Poles are predominantly 10/2kN concretes and iron rails. Insulators are also 1950's low creepage distance and problems of cracking and auto-reclosing during rain periods are experienced.
Chateau	Whakapapa Ski field and village	28.6	24	6,012,260	133	Supply to Chateau and Whakapapa Ski Field. Overhead sections renewed and replaced with cable. About 60% is heavy armoured cable.
Coast	Remote rural area around Marokopa	84.1	24	3,333,426	321	Several asset groups renewed. Generally aging rural feeder with parts exposed to severe coastal conditions. Mostly small ACSR conductor that is showing corrosion problems in some areas. Poles predominantly 10/2KN concretes and iron rails with low creepage distance insulators and problems of cracking and auto reclosing during rain are experienced. Difficult feeder to automate due to lack of communication signals from existing repeaters.
Gravel Scoop	South east of Otorohanga	95.1	41	3,178,883	523	Average condition rural feeder supported by a mixture of wooden poles and 10/2KN concretes. Sections have been renewed.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Hakiaha	Central area of Taumarunui	5.7	31	1,271,941	294	Supplies central area of Taumarunui and is partly underground. Becomes a rural feeder when it leaves town boundary. Rural part is small ACSR conductor and pole types are mixed with some wooden, 10/2KN concretes and iron rails. Insulators mostly low creepage distance. Some renewal work completed.
Hangatiki East	Area east of Hangatiki	20.0	37	495,601	71	Average condition rural feeder with two large limestone processing plants connected. Conductor size is less than ideal in places. Pole strengths should ideally be higher given the span lengths and conductor size. Some renewal work completed.
Hirangi	SWER feeder to semi residential area around Turangi	6.7	33	310,317	369	Totally SWER feeder on outskirts of Turangi. Average condition. Some renewal work completed.
Huirimu	Supply to rural area south of Arohena	44.9	36	995,477	155	Average condition in dairying and dry stock area. Most of feeder is constructed of light conductor and supported on iron poles. The insulators are mostly of the 1950's short creepage distance type. Some renewal work completed.
Kuratau	Kuratau	37.9	30	3,260,164	1287	Extensive renewal and strengthening completed.
Mahoenui	Supply to Mahoenui and surrounding rural areas	107.8	24	3,906,878	277	Average condition. Most of feeder is supported on 10/2KN concrete poles. Some renewal work completed.
Maihiihi	Rural area north east of Otorohanga	102.6	31	4,444,056	887	Rural feeder supplying dairying load. Has been mostly renewed over the last 10 years. Average to good condition.
Mangakino	Supply to Mangakino	22.9	38	643,635	489	Average condition. Some asset groups have been renewed. Mixture of poles.
Manunui	Rural area to south and east of Taumarunui	85.1	43	2,243,256	576	Supply to Manunui village and rural area. Generally in reasonable condition but design is inherently light. Poles mainly 10/2KN concrete and iron rails. Incorporates the old Affco Feeder. Renewal work and some upgrading is planned.
Matapuna	Supply to western side of Taumarunui	16.8	44	1,551,859	1041	Good condition (once renewals completed). Mostly supported by concrete poles with 10/2KN strength ratings. Renewal of rural section completed or underway.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
McDonalds	Rural area to the south of Otorohanga	37.5	32	1,582,787	447	Supplies dairying and industrial load. Design is weak with long spans of larger size ACSR on 10/2KN concrete and iron rails. Insulators are 1950's low creepage distance and problems of cracking and auto-reclosing during rainy periods are experienced. Feeder has a voltage problem. Overall in average condition with some renewal work completed.
Miraka	Part of Mokai Energy Park	0.9	25	109,151	1	Newly constructed as part of energy park. About 50% is underground utilising heavy conductor.
Mokai	Mokai rural area including western bays area of Lake Taupo	75.7	29	3,349,686	309	Average condition. Mostly supported on mixture of hardwood and concrete 10/2kn poles. Some renewal work completed. Consists of some long spans with close conductor spacings that can clash in wind. Insulators are also mostly 1950's low creepage distance type that are susceptible to cracking and causing auto-reclosing when it rains. Some renewal work completed; more planned.
Mokau	Mokau coastal area	129.7	33	5,238,320	634	Long coastal 11kV feeder in very harsh environment. Gives problems with drop-out fuse connections and insulator failures. Has inherent line design weakness in the Awakino Gorge. Some renewal work completed.
Mokauiti	Rural area south west of Piopio	74.2	35	2,119,840	174	Average condition. Mostly supported on mixture of hardwood and concrete 10/2KN poles. Some long spans with close conductor spacings that can clash in wind. Insulators are mostly 1950's low creepage distance types than are susceptible to cracking and causing auto-recloses when it rains. Some asset groups have been renewed.
Motuoapa	Supply to Motuoapa area	2.5	33	605,609	395	East Taupo. Partly renewed and partly very old construction. Old construction will be renewed as part of 15 years renewal programme. Overall average condition.
National Park	Supply to the National park area including the village	44.6	35	1,903,110	437	Partly renewed, partly in very poor condition with long spans of light conductor on 10/2KN concrete and iron rails. Will be renewed and poles strengthened as part of 15 year line programme. Overall in average condition.
Nihoniho	Supply to the Nihoniho and Matiere areas	30.3	39	568,816	67	Remote lightly constructed rural feeder in poor to average condition with few customers. Will be renewed with some strengthening in key places as part of 15-year programme. (Some of this work has been completed.)

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Northern	Area north of Taumarunui	124.3	35	5,476,480	1227	Average condition. Is a long feeder. Some asset group renewal work has been completed. Most of the feeder is supported by 10/2KN concrete poles and iron rails. There are also two large SWER systems that can tie with other feeders attached to the end of the line. This feeder is the most heavily loaded out of Taumarunui.
Ohakune Town	Ohakune town supply	12.9	32	2,303,556	878	Urban supply to Ohakune that is generally in average condition. Several security improvement projects have been completed and more are proposed to bring feeder up to industry standard for a supply to a popular tourist area. Some renewal /strengthening work has been completed; more is planned.
Ohura	Ohura and surrounding remote rural areas	181.7	43	3,248,748	381	Lightly constructed feeder in remote area. Feeder overall is in average condition. The area covers a large section of a remote part of the King Country, with a low customer density and a declining population base. Designs associated with renewal have to focus on maximum improvement for spend and not over investing on lines in a very remote area. Supplies several interconnecting SWER systems.
Ongarue	Large rural area around Ongarue	122.2	43	2,390,064	260	Lightly constructed feeder in remote area. Feeder overall is in average condition. Has low customer density and a declining population base. The area it covers is a large section of a remote part of the King Country. Designs associated with renewal have to focus on maximum improvement for spend and not over investing on lines in a very remote area. Supplies several interconnecting SWER systems. (Some renewal work has been completed.)
Oparure	Supply to an area west of Te Kuiti	80.9	28	3,722,493	927	Rural feeder of light construction. Suffers from long spans of light conductor in a few places. Mostly supported by 10/2KN concrete and iron rails. Low creepage distance 1950's insulators have given trouble on this feeder. Some renewal work has been completed to address the worst of these problems.
Oruatua	Eastern side of Lake Taupo, north of Motuoapa	8.9	34	861,234	388	East Taupo. Partly renewed and partly very old construction. Old construction will be renewed as part of 15 year renewal programme.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Otorohanga	Supply to most of town plus rural area to southwest	53.3	26	3,016,045	1146	Overhead urban and rural feeder. Urban area in average condition. Rural section has been partly renewed. Fault current levels are high and connections are often destroyed when through fault currents occur. Pole population is mixed but predominantly 10/2KN concrete and iron rails. More renewal work is planned.
Otukou	Area around Sir Edmund Hillary Outdoor Pursuits Centre	6.5	41	342,753	96	Relatively short feeder on Central Plateau with SWER systems attached. Light construction has trouble supporting the snow loadings it is exposed to on the Central Plateau. Some renewal completed. Mostly supported on 10/2KN concrete poles and iron rails. Average condition.
Paerata	Part of Mokai Energy Park	4.0	21	51,806	8	Mostly new - constructed as part of energy park supply. It does include some older sections that were part of the Mokai feeder.
Piopio	Supply to Piopio village and surrounding rural area to north	55.1	29	2,044,375	453	Rural settlement and rural supply. Good condition. Feeder does have long spans with close conductor spacings. It is predominantly supported by 10/2KN concrete poles. Some renewal completed.
Pureora	West of Whakamaru including supply to Crusader Meats	52.1	32	2,058,820	162	Average condition. Parts have been renewed. Supplies dairying and industrial load. Medium size conductor on mix of wooden and 10/2KN concrete poles. Has had some asset group renewal work completed. Ideally two more regulators and some upgrading is needed to support voltage levels. (Regulators are included in the plan.)
Rangipo / Hautu	Supply to areas east of Turangi	42.4	39	2,091,857	851	Sections have been rebuilt in conjunction with work on East Taupo 33kV. Remainder is lightly constructed and in average condition. Some renewal has been completed.
Rangitoto	Area west of Te Kuiti	77.3	34	2,821,207	737	Average condition. Some renewal work completed. Mixture of concrete 10/2KN, wooden and iron rail poles. Has some long spans with close conductor spacings.
Raurimu	Raurimu village and rural areas to east, west and south	171.4	38	2,584,175	312	Average to poor condition. Line has some major SWER lines connected that go deep into the King Country. The feeder is predominantly supported by iron rails. Limited income is available from this extremely rugged and remote area.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Rural	Rural area surrounding Taharoa	6.0	32	925,778	106	Average to poor condition rural feeder but exposed to harsh west coast seaside environment. Has a mixture of wooden, concrete and iron rail poles. Corroded hardware and conduction is an issue with this feeder. Some asset group renewal work is completed. Feeder has small customer numbers and renewal is balanced against returns.
Southern	Area south of Manunui including connection for Piriaka distributed generation	124.4	42	2,690,938	631	Generally in good condition. Much of the feeder has conjoint SWER systems. Predominantly supported on 10/2KN concrete poles. Has a number of long spans that are prone to clashing during periods of high wind speeds. Some renewal work has been completed.
Tangiwai	Area east of Ohakune	90.8	34	4,419,082	627	Average condition. This feeder is located in a moderate to heavy snow area. The inherent design has no allowance for ice loadings. Some asset group renewal work has been completed . The poles are either iron rails or 10/2KN concretes.
Te Kuiti South	Part of Te Kuiti town and rural area to south.	41.3	38	1,445,538	581	Average condition feeder principally supported on 10/2kN concrete poles. Has a number of long spans that are prone to clashing during periods of high wind speed. Have also had a number of problems with 1950's short creepage distance insulators that discharge to pins, crack and cause auto-reclosing during rain. Some renewal work completed.
Te Kuiti Town	Central area of Te Kuiti	2.0	34	374,344	151	Average condition. Mostly supported by 10/2KN concrete poles. Has a mix of AL and CU conductors. Suffers from joint failure when exposed to through fault currents. Some renewal work completed.
Te Mapara	Area south east of Piopio	62.9	34	2,065,806	229	Rural feeder in good condition. Some asset groups have been renewed. Mixture of wooden and concrete poles. Some renewal work completed.
Tihoi	Western bays area Lake Taupo	62.5	35	1,609,737	208	Average condition. Parts of feeder have an on-going tree problem due to a large number of tree blocks owned by absentee landowners. Some renewal work completed.
Tirohanga	Western bays area Lake Taupo	76.7	34	2,575,234	228	Average condition. Some renewal work completed; more underway.
Tokaanu	Tokaanu	1.2	22	279,952	89	Mainly underground cable. Good condition. Renewal work completed.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Tuhua	Remote rural area around Ongarue	40.8	43	458,647	149	Average condition remote rural feeder supplying remote area. Has a number of SWER lines connected towards its ends. Supported by mostly 10/2KN concrete poles and iron rails. Some renewal work has been completed.
Turangi	Supply to Turangi Town and surrounding area	8.6	36	1,807,526	1090	Mostly underground feeder supplying Turangi town. The overhead section that supplies the underground is in poor condition with low strength poles carrying a double circuit. Work on this section of line is planned.
Turoa	Turoa ski field and urban rural area to bottom of mountain	59.9	38	7,654,898	427	Main purpose is supply to Turoa ski field. The feeder is constructed with heavy conductor on moderate strength poles. There are one or two long spans where there are inadequate conductor spacings. The overall condition is good but the line is generally constructed under strength for the heavy snow area it is in. Some strengthening and renewal work has been completed.
Waihaha	Area around south western of Lake Taupo	116.0	32	2,843,428	269	Part of feeder is in good condition, part in poor condition. The poor section was once part of the original 33kV single phase and 11kV SWER arrangement that supplied the area. The lines are mostly supported on 10/2KN concrete poles and iron rails. Spans are long and conductor sizes are small. Expenditure needed on renewals is hard to justify. Some renewal work has been completed.
Waiotaka	Waiotaka	10.2	18	353,155	7	Originally part of the Rangipo / Hautu feeder. New container substation was commissioned in 2007 to provide security of supply to prison and surrounding area. Average condition. Some renewal work has been completed.
Waitomo	Area north of Te Kuiti and major lime plant	11.9	32	812,196	432	Average condition rural feeder supplying part of Te Kuiti town and rural area to the north. Medium size conductor mostly supported on 10/2KN concrete poles. Has some larger spans with close conductor spacing. Some renewal work completed.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, VALUE AND NOTES						
Feeder	**Location Description**	**Length (km)**	**Average Age**	**RAB**	**Feeder ICPs**	**Asset Notes**
Western	Rural area north west of Taumarunui	136.5	44	2,452,123	440	Supplies part of Taumarunui and travels west along the Whanganui River until breaking into a number of SWER systems. Asset group sections have been renewed and security has been increased by establishing a link to the Northern feeder. Generally in poor condition with lines being mainly supported by 10/2KN concrete poles and iron rails. Some renewal work has been completed.
Whakamaru	Whakamaru village and surrounding dairying areas	68.8	27	3,512,296	575	Rural feeder supplying dairying area and ex NZED Whakamaru Village. Sections have been renewed. Overall feeder is in average condition.
Wharepapa	Large rural dairying area west of Arohena	106.4	41	2,186,855	404	Long rural feeder supplying dairying area. Includes a large amount of 16sq.mm Cu conductor supported on iron rail and hardwood poles. Some asset group renewal work completed. Additional automated switches were installed as part of the 2006/07 programme to try and improve reliability in this area. Some renewal work completed. Renewal of conductors is included in the plan.
Winstones	Area east of Ohakune					Part of Ohakune feeder. Good condition; renewal is planned in the future.

TABLE 3.19: DISTRIBUTION FEEDERS, VOLTAGE, AND DESCRIPTION. QUANTITY, AGE, VALUE AND CONDITION

Note: RAB values for lines are as defined in the 2004 ODV handbook. It also includes the distribution transformers and switchgear distributed along the feeder, but does not include substations.

Age Profiles

The overall age profile of 11 kV feeders is indicated in Figure 3.11.

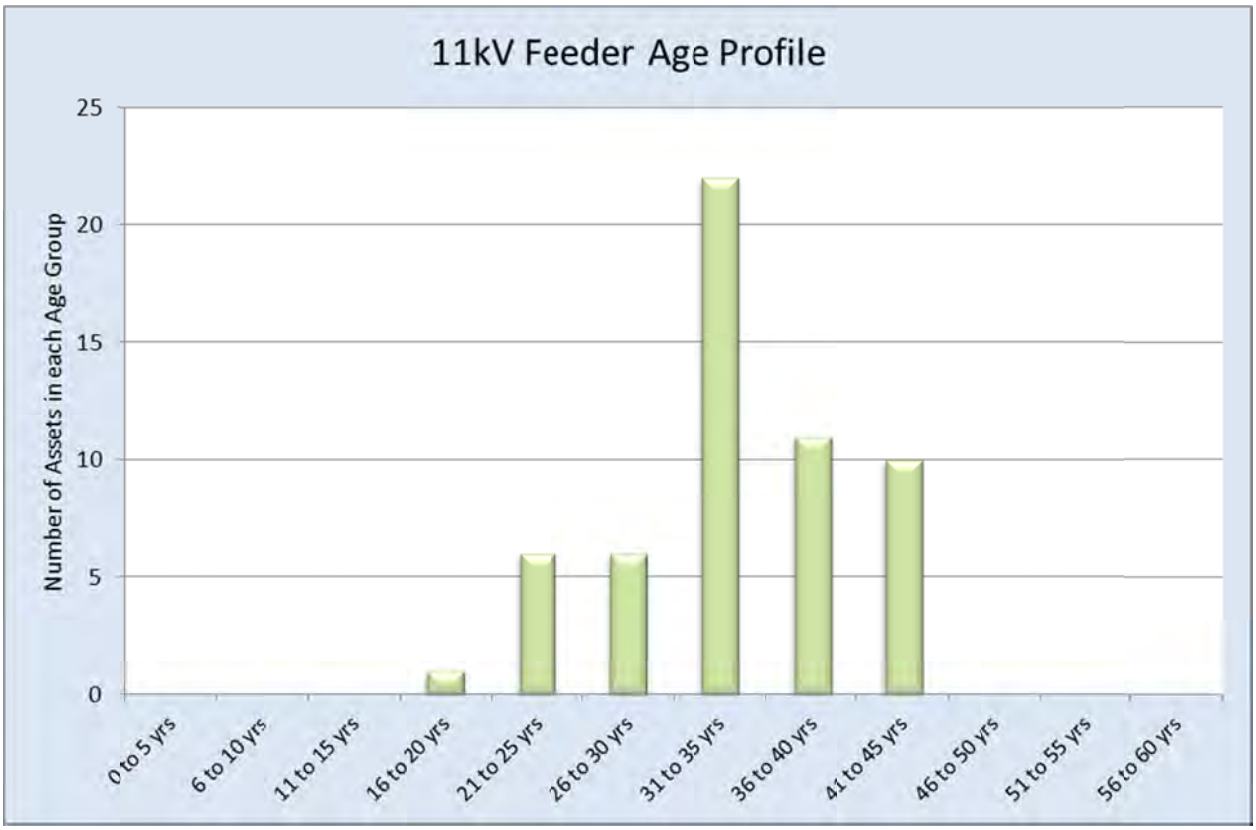


FIGURE 3.11: AGE PROFILE OF 11 KV FEEDERS

The present development and renewal strategies will cause the age profiles to narrow and tend towards the 25 to 35 year range. This will ensure there is no shock to replace entire assets provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur. The renewal programme will result in continuous asset technology upgrade, i.e. the latest technology; materials, etc. will continually be used for renewals.

Common modes of failure with feeder assets in approximately the order of their effect on network performance are:

1. *Vegetation*

   Trees falling across lines or branches blowing into lines cause significant problems with overhead lines.

2. *Connection failures*

   Most conductor connection failures occur with jumpers between lines or on to equipment such as dropout fuses or Air Break Switches. The major cause of these is poor workmanship and inappropriate equipment. Most problems occur when dissimilar metals are involved. A large number of problems occur after the passage of fault current.

3. *Insulators*

   Historically two types of insulators have been used on 11 kV networks in New Zealand. These are the 821 and 1130 categories. The 821 have lower technical ratings than the 1130. The most significant of these ratings is the creepage distance; 185mm as opposed to 250mm. Most of the TLC network including SWER systems has been constructed with the 821 insulators. After 40 years of exposure to the King Country environment, most of which receives regular fertiliser applications, these insulators

fail. Finding failed insulators (that normally crack due to pin corrosion initiated by corona discharge) is very difficult with presently available testing tools.

Figure 3.12 illustrates a typical 1950's 821 insulator that has discharged to the pin and then cracked.

FIGURE 3.12: EXAMPLE OF AN 821 INSULATOR THAT HAS DISCHARGED TO PIN.

4. *Conductor failures*

Span lengths in the TLC networks tend to be long as lines go from hilltop to hilltop. Cross arm lengths by industry standards are short. This leads to conductor clashing mid-span either caused by wind, birds, or trees pushing wires together. After a period of clashing and recloses, wires burn through and fall to the ground. Adding to this problem, many of the older conductors in the northern network are copper. Copper work hardens and becomes brittle with age. After clashing, conductor failures can become common.

Clashing can cause protection to operate incorrectly. Often a substation breaker will operate instead of a field recloser because of clashing between the two caused by fault current passage into a remote fault. Joints in conductors often fail after the passage of fault current. Fault current has to be controlled to minimise these effects.

Many of the rural feeders in the TLC network were constructed by farmers using short poles to establish supply into rural areas. This very minimal, low cost approach does sometimes result in conductor-to-ground clearances falling to below those stated in codes of practice. Sometimes these low conductors get tangled in machinery such as maize harvesters and conductor damage occurs.

5. *Cross arm failures*

   Most cross arm failures are caused by old age and rot.

6. *Pole failures*

   Old age, rot, lack of staying, corrosion and poor design cause pole failures.

7. *Private lines*

   Approximately 800km of 11 kV lines connected to the TLC network are classified as private lines. This means responsibility for maintaining these lines rests with the landowner. Landowners are often reluctant to carry out maintenance.

   Private lines are fused at tap off when they are found to be causing problems or as part of the 15 year renewal programmes. Lines inspectors do assess private lines when inspecting for the 15 year cycle and pass this information onto line owners so that they can approach a contractor and get repairs completed.

   Lines inspectors recheck known private line problems after a reasonable period and if they have not been repaired, then further follow-up results. This includes discussing the issue with the owner again and, if still no response, then TLC may disconnect and/or notify the Energy Safety regulator.

   The new Electricity (Safety) Regulations outline private line responsibilities more clearly than the previous legislation. Specifically the fines for non-compliance are now attached to the individual regulations.

3.3.3.2 Distribution Cables

Voltage

Most of the distribution cables connected to the TLC network operate at 11 kV. There are a number of sections of 11 kV cable connected to SWER lines that operate at 11 kV to earth and 6.6 kV to earth.

Description and qualities of assets

Distribution cables are dispersed throughout the network. The areas with most significant cabling are:

- Feeders coming out of Te Waireka (Otorohanga), Waitete (Te Kuiti), and Borough (Taumarunui) zone substations.
- Parts of Taumarunui.
- Parts of Ohakune.
- Turangi Town (ex hydro construction town).
- Whakapapa Ski Field.
- Turoa Ski Field.
- Small sections of feeders under Transmission lines or into/away from modular substations.
- Recent subdivisions.
- Short sections of cable into ground mounted substations.

The sum of cabling on the two ski fields equates to about 50% of The Lines Company cable reticulation. Earlier table 3.8 lists the individual feeders and the lengths of cable included in each feeder. Table 3.20 summarises cable data.

CABLE SUMMARY			
Description	**Voltage**	**Total km**	**RAB**
11 kV UG Light (< 50mm AL) XLPE	11	9.03	728,332
11 kV UG Medium (>50mm, < 240mm AL) XLPE	11	97.12	13,215,829
11 kV UG Heavy (>240mm, < 300mm AL) XLPE	6.6	1.21	151,866
22 kV UG Light (< 50mm AL) XLPE	11	1.61	159,517
33 kV - Cables (< 240 mm AL) XLPE	33	1.71	335,503
Underground Medium - with HV (<240mm) PILC	11	1.47	50,177
Underground Medium - with HV (<240mm) XLPE or PVC	11	3.10	103,747
Underground Medium - with HV (<240mm) XLPE or PVC	400	2.08	69,137
Underground Heavy - with HV (>240mm) PILC	11	0.05	2,350
Underground Heavy - with HV (>240mm) XLPE or PVC	11	2.51	115,206

TABLE 3.20: CABLE QUANTITIES AND VALUES

Key:
PILC - Paper Insulated Lead Covered Insulation
XLPE - Cross-Linked Polyethylene Insulation
PVC - Polyvinyl Chloride Insulation

Age Profiles

The overall age profile of distribution cables is illustrated in Figure 3.13.

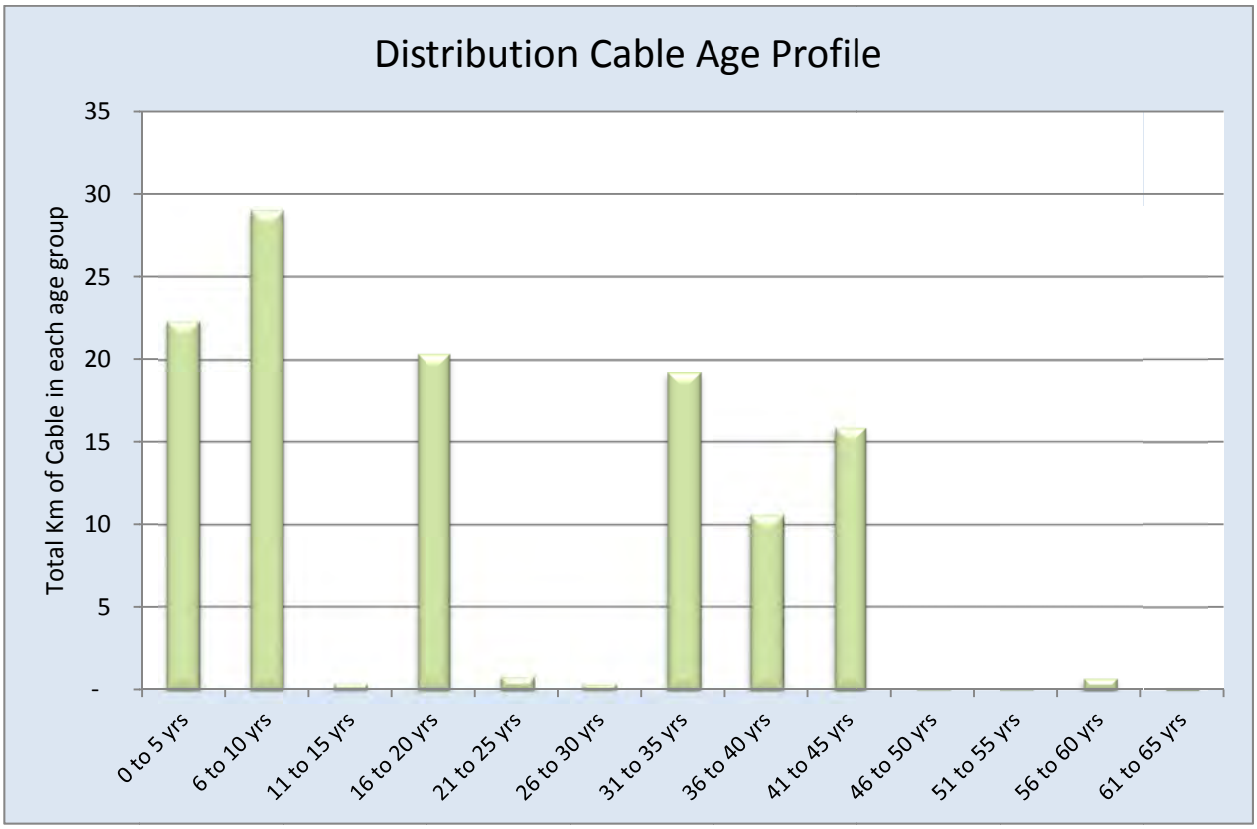


FIGURE 3.13: AGE PROFILE OF DISTRIBUTION CABLES

The age of cables corresponds to subdivision activity and ski field development.

Condition of Assets

Much of TLC's legacy distribution cabling is older generation XLPE cable. Many low quality terminations have been renewed over the last few years. Generally, TLC's cable assets are in average industry condition. Sections of cable that cause problems are being renewed (normally as part of "emergent works" – see Sections 5 and 6). This will ensure there is no funding shock to replace entire assets.

Most of the ski field cables consist of steel wire armoured cables laid directly on the ground. There are on-going hazard control problems with these as changes occur in the mountainous environment where they are laid. Snow groomers damage these cables from time to time.

3.3.3.3 Distribution Transformers

Voltage Levels

Except for a few 6.6 kV to 240 V and 33 KV to 415 V units, all of TLC distribution transformers are 11 kV to 415/240 Volt.

Distribution and Quantity of Assets

The majority of TLC's distribution transformers are 30 kVA or less, 11 kV to 240 V. These units are standard pole hanging transformers. The pole hanging stock includes various transformers up to and including 200 kVA.

There are approximately 400 ground-mounted transformers, in various configurations; from exposed bushing units in sheds through to modern enclosed "I" tank units. This population is similar to other network companies' stock.

TLC also has a stock of about 65 11/11 kV transformers used to supply the 60 SWER systems connected to the network.

The quantity and value of distribution transformers are summarised in Table 3.21.

DISTRIBUTION TRANSFORMER SUMMARY		
Transformer Description	**Total Number**	**RAB**
Pole Mounted Single/Two Phase		
Up to and including 15 kVA	2672	7,735,454
30 kVA	394	1,158,962
60 kVA	46	151,461
100 kVA	2	7,830
> 100 kVA	2	18,773
Pole Mounted Three Phase		
Up to and including 50 kVA	1210	5,718,119
100 kVA	155	1,308,266
200 kVA	30	401,973
300 kVA	15	233,983
500 kVA	3	46,997
>500 kVA	9	341,220
Ground Mounted Single Phase		
Up to and including 200kVA	19	70,036
Ground Mounted Three Phase		
Up to and including 85kVA	45	427,540
100 kVA	50	556,189
200 kVA	186	2,227,686
300 kVA	98	1,487,462
500 kVA	24	554,744
>500 kVA	18	578,616

TABLE 3.21: QUANTITY AND VALUE OF DISTRIBUTION TRANSFORMERS

Age Profile

Figure 3.14 indicates TLC's transformer age profile.

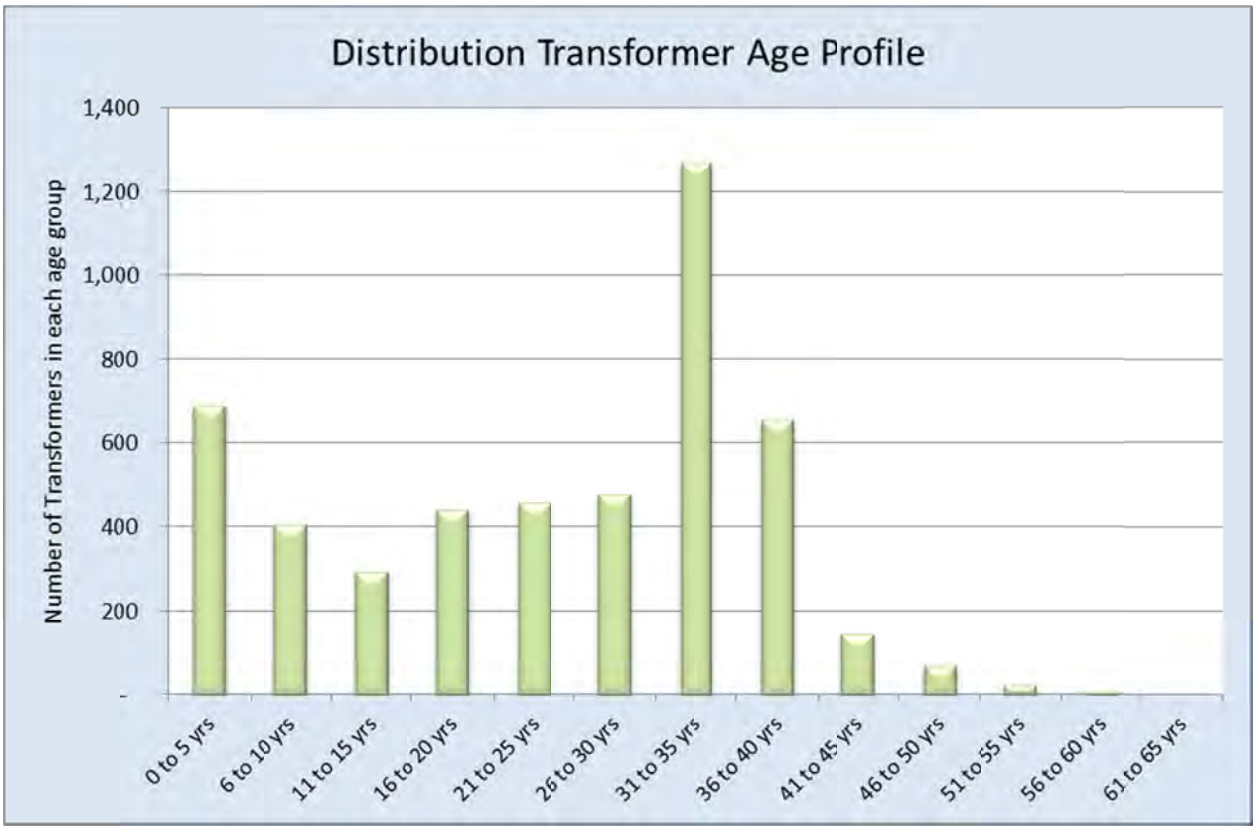


FIGURE 3.14: DISTRIBUTION TRANSFORMER AGE PROFILE

It is expected that the age profile of distribution transformers will shift slightly to the newer end of the graph as the renewal programme runs through the planning period. This will ensure there is no shock to replace large numbers of transformers at once provided the 15-year inspection and hazard control renewal cycle is continued.

Note: TLC is not scrapping transformers that can be refurbished or reused. Only transformers that are old, in poor condition or have failed and are not economic to repair are being written off. (See lifecycle section for more details on this.)

Condition of Assets

The distribution transformer stock is in average condition.

There are a number of reasons why transformers fail prematurely. The reasons for failures include:

- Lightning.
- Accident. (Vehicle, vegetation)
- Water damage.
- Broken bushings.
- Fault current passage.
- Corroded cases.

3.3.3.4 11 kV Switchgear

Voltage Level

The switchgear detailed in this section is that associated with the distribution of voltage of 11 kV. It excludes sub-transmission and zone substation equipment.

Description and Quantity of Assets

Table 3.22 describes the quantities, number, and value of distribution switchgear assets. (2011 RAB)

11 kV DISTRIBUTION SWTICHGEAR AND CONTROL ASSETS		
Type of Link	**Number**	**RAB**
11 kV ABS Load Break	11	93,077
11 kV ABS Two and Three Phase	436	615,498
11 kV Circuit Breakers	140	1,553,965
11 kV Fuses in Transformers	805	790,355
11 kV Line Reclosers	90	876,753
11 kV Oil Switches	4	38,993
11 kV Ring Main Units	83	1,070,411
11 kV RTE Integrated Transformer Switches	46	674,717
11 kV Sectionalisers	72	397,136
11 kV Solid Isolating Links	427	502,050
11 kV Transformer Fuses	4765	4,922,447

TABLE 3.22: 11 KV DISTRIBUTION SWITCHGEAR AND CONTROL ASSETS

Age Profiles

Figure 3.15 indicates the age profile of 11 kV distribution switchgear assets.

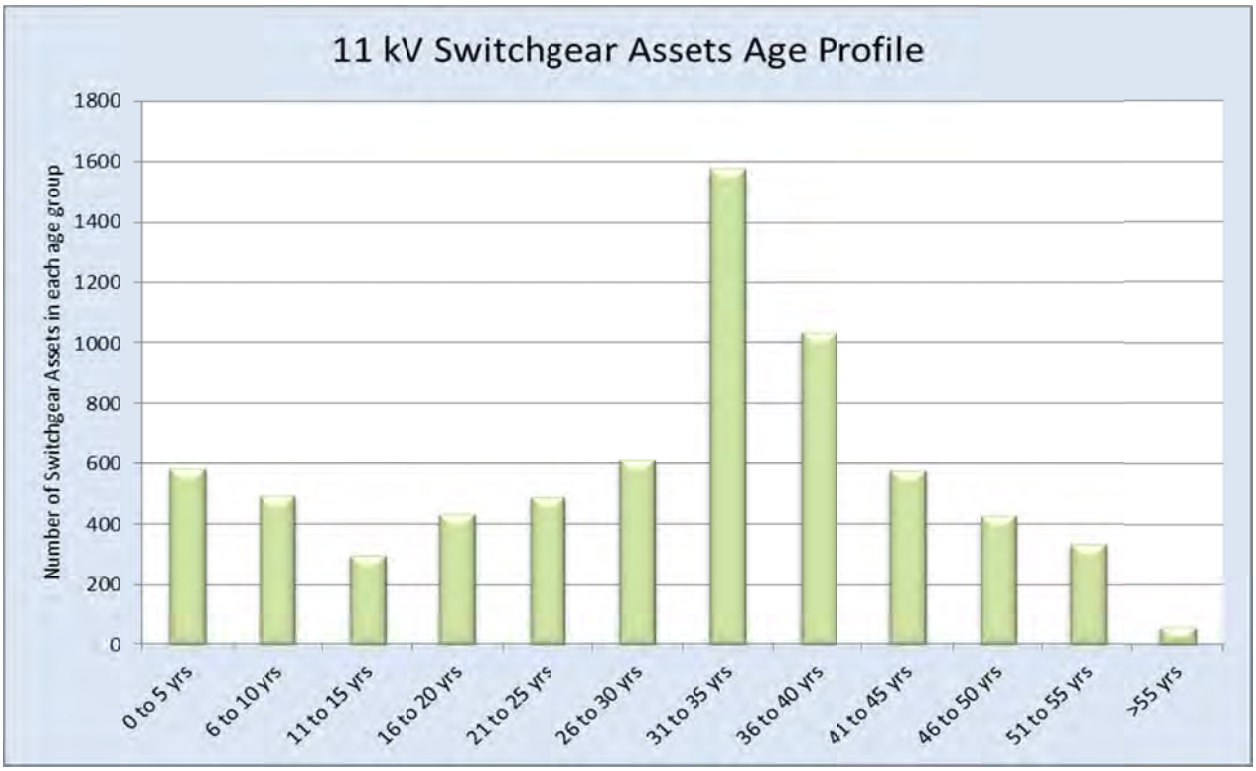


FIGURE 3.15: AGE PROFILES OF 11 KV SWITCHGEAR ASSETS

The new switchgear coming into the network as part of the renewal programme has shifted the age profile to the left of the chart as compared to earlier years. (Older units are also being renewed on failure and as part of the 15-year line renewal programme.) This will ensure there is no shock to replace large numbers of switches provided the renewal programme is continued and emergent problems are repaired when they occur. The renewal programme will also result in continuous asset technology upgrades, i.e. the latest technology, materials etc.

Condition of Assets

The distribution switchgear assets condition tends to track that of general feeder condition. TLC has had significant problems with early failure of dropout fuses. The main reasons for this have been found to be:

- Poor manufacturing quality.
- Poor connections.
- Corrosion.

Figure 3.16 illustrates a typical mode of corrosion failure with dropout fuses.

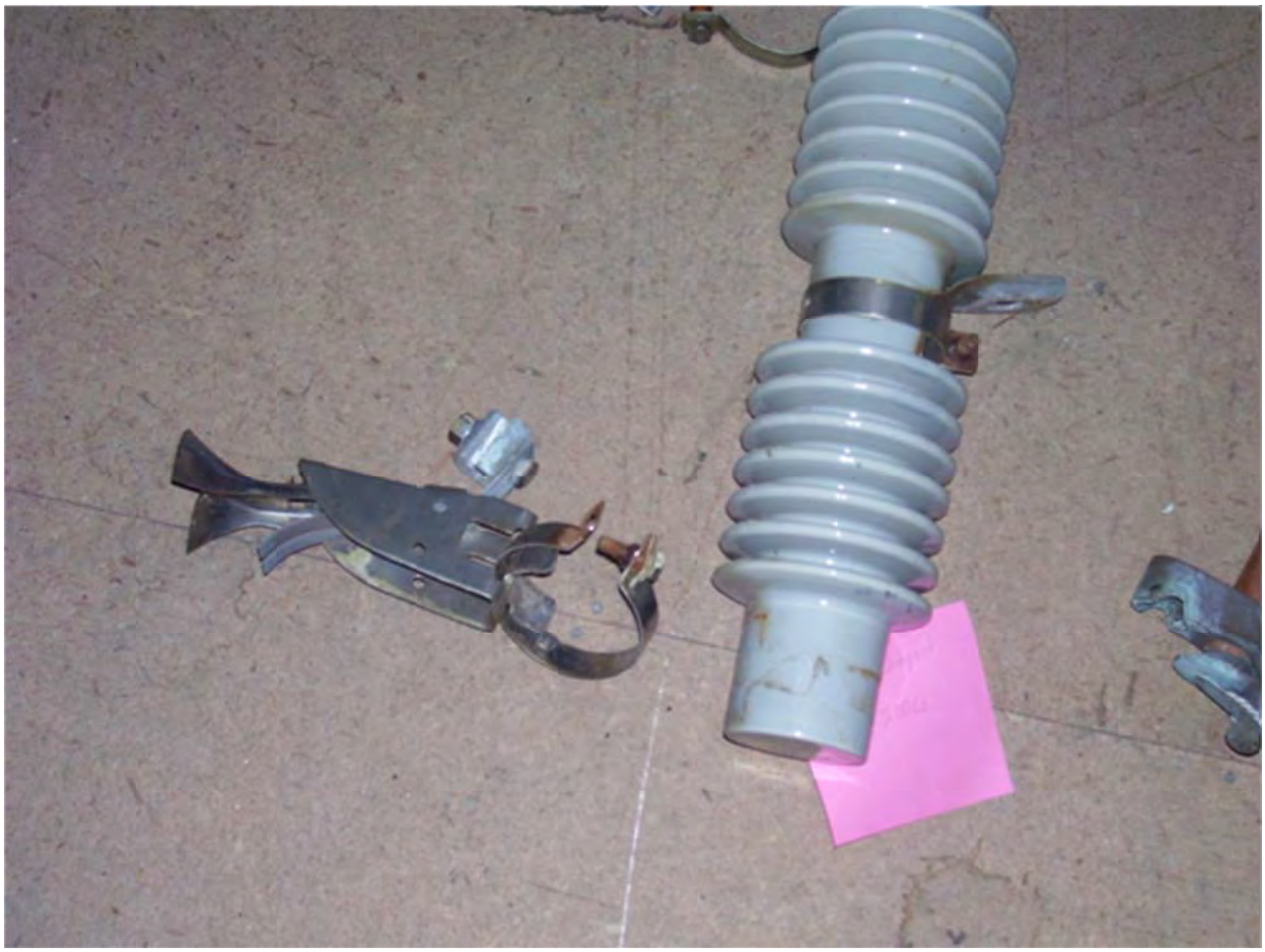


FIGURE 3.16: EXAMPLE OF FAILURE OF A DROPOUT FUSE.

Air break switches generally give problems with electrical connections onto the units and operating mechanisms. Most other switchgear has been found to perform to manufacturers' specifications.

3.3.4 Distribution Network Low Voltage

Voltage Level

The voltage level of the low voltage network is 400/230V.

Description and Quantity

TLC records of the low voltage network vary in terms of data accuracy. There are good records of recent work. Records of overhead rural and older urban network can be incomplete and in these situations are based on best estimates.

More detail of LV systems is being collected as part of inspections associated with the renewal programme. This data is being progressively entered into the network data system. Table 3.23 lists the estimated quantities and RAB value of the low voltage network.

BREAKDOWN OF LV ASSETS		
Description	**Quantity**	**RAB**
LV Concrete	28.7 km	337,741
LV Concrete Underbuilt	55.8 km	1,194,084
LV Wood	146.8 km	737,487
LV Wood Underbuilt	158.9 km	1,258,034
Streetlight Concrete and Concrete Underbuilt	18.7 km	157,497
Streetlight Wood Underbuilt	89.3 km	569,705
Underground Cables	183.59 km	9,668,997
Pillar Boxes	3707 units	129,200

TABLE 3.23 ESTIMATED QUANTITIES AND VALUE OF LOW VOLTAGE OVERHEAD DISTRIBUTION ASSETS.

Low voltage underground cables exist to some extent in most township areas. Turangi town has the most extensive low voltage network. As mentioned previously, there are few low voltage ties in these networks.

The low voltage underground assets include service (pillar) boxes of which TLC has approximately 3700.

Age Profiles

The age profile of LV lines is indicated in Figure 3.17.

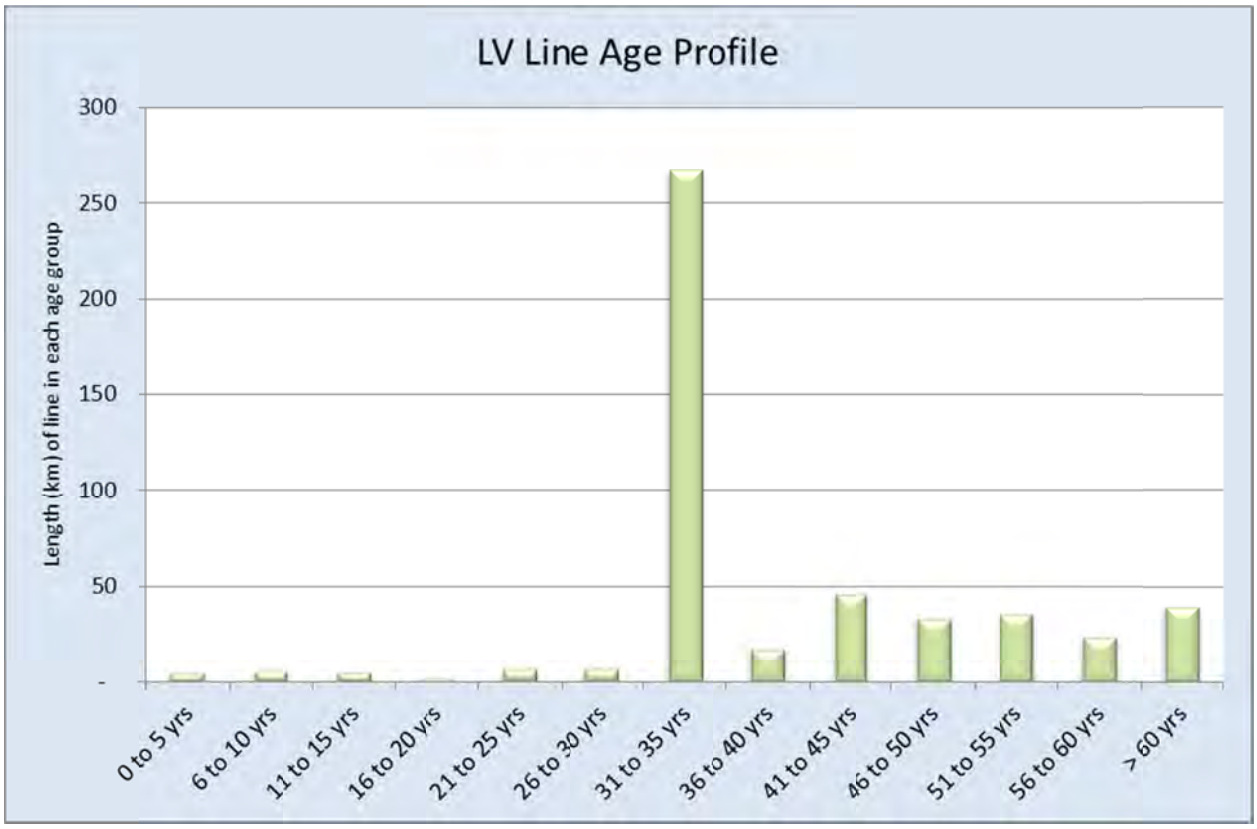


FIGURE 3.17: AGE PROFILES OF LV LINES

The estimated age profiles of LV lines will generally tend to move and shadow the pattern of 11 kV lines during the planning period.

Low voltage lines and related equipment especially service boxes are being inspected and renewed. Overhead systems form part of the 15-year line renewal programmes. Service boxes form part of the 5-year programme. This will ensure there will be no shocks to replace the entire low voltage assets provided the 5 and 15 year inspections and renewal cycle is continued and emergent problems are dealt with when they occur. The Plan includes renewal of sections of poor LV conductor in several holiday areas.

Condition of Assets

Low voltage overhead systems were traditionally not constructed with covered conductor. To solve clashing problems in high winds, spacers have been fitted in many places.

Historically LV systems were not designed with back feeds. Underground systems can suffer from poor workmanship with often little labelling and with cable routes being quite different to records. Inspections and renewals are improving this situation.

TLC has inspected, numbered, and recorded its service boxes. This inspection revealed a number that were a significant hazard to the public and staff. These boxes have been renewed and repaired. Further repairs of boxes that present a medium to low risk hazard have been included in plans.

Underground cabling systems installed in Ohakune, and most of the southern network, during the 1970's and 1980's consist of solid core, double pass, PVC insulated single core, solid aluminium cables. Often no marking or mechanical protection was installed above cables in trenches. These are prone to corrosion and mechanical damage.

3.3.5 Description of Supporting or Secondary Systems

3.3.5.1 3.6.1 Load Control (Ripple Injection) Plants

Table 3.24 provides information describing the Load Control (Ripple Injection) plants.

LOAD CONTROL PLANT SUMMARY							
Location	**Design**	**Freq**	**Voltage**	**Age**	**Mechanism**	**Condition**	**RAB**
Arohena	Landis & Gyr	725 Hz	11 kV	46	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 years of operation will be needed as relays are replaced with advanced meters.	0
Gadsby Road	Landis Gyr	725 Hz	11 kV	14	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.	732
Maraetai	Landis Gyr	725 Hz	11 kV	14	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 years of operation will be needed as relays are replaced with advanced meters.	915
Te Waireka	Landis Gyr	725 Hz	11 kV	14	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.	839
Wairere	Landis Gyr	725 Hz	11 kV	15	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.	643
Waitete	Landis Gyr	725 Hz	11 kV	14	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.	896
Hangatiki	Landis Gyr	317 Hz	33 kV	0	Modern Electronic	New	126,895
National Park	Zellweger	317 Hz	33 kV	3	Electronic	Good	117,234
Ohakune	Zellweger	317 Hz	33 kV	3	Electronic	Good	117,234
Ongarue	Zellweger	317 Hz	33 kV	3	Electronic	Good	117,234
Tokaanu	Zellweger	317 Hz	33 kV	0	Electronic	Good	126,895
Whakamaru	Landis Gyr	317 Hz	33 kV	1	Modern Electronic	New	135,248

TABLE 3.24: SUMMARY DESCRIPTION OF LOAD CONTROL PLANT

The southern system injects into the 33 kV network, which has the advantage of removing any difficulty of adding 33/11 kV zone substations. The 317 Hz system also has the advantage of enabling good signal propagation throughout the downstream network. The present plant controllers and relays are not set up to allow load to be switched if the frequency begins to fall. There are little known harmonic interference problems with the southern plants. As outlined earlier, the northern regions are supplied by old 11 kV 725 Hz plants that provide marginal signal levels to many areas.

There are several areas (approximately 800 customers) that have no load control signal coverage and a similar number are estimated to have marginal coverage until the lower frequency relays incorporated in advanced meters are deployed. In the northern region, it is not possible to add additional 33/11 kV transformers and create new zone substations without the loss of load control signals. Figure 3.18 indicates the age of load control plants.

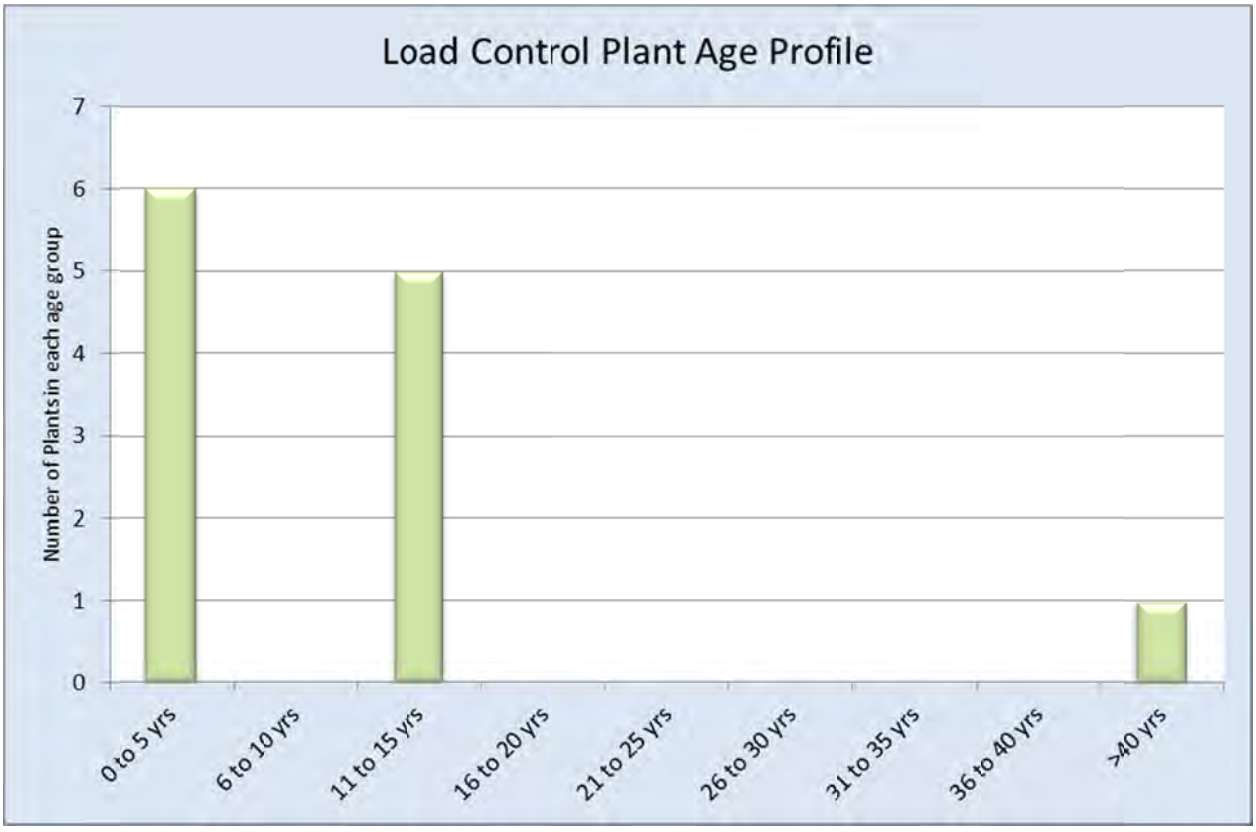


FIGURE 3.18: AGE PROFILES OF LOAD CONTROL PLANTS

The commissioning of two new 33 kV injection plants at Hangatiki and Whakamaru will, in the long term, replace the six 725 Hz plants and create a change in the age profile. Labour for replacing relays in the northern area is included is the planning period estimates. Note: This has been delayed slightly to better align with more demand metering rollouts.

A full evaluation of the economics of renewing the northern plants was completed during 2008/2009.

This study showed that renewal of the northern plants during 2009/10 was justified. Part of this justification came from the benefits that occur from TLC's unique demand based billing. The evaluation included benefits from:

- Reduced transmission connection charges.
- Costs associated with maintaining and operating present system.
- Reduced income from inability to control and set demand charges.

The study excluded difficult to quantify values such as income from the load reduction market, benefits from being able to use capacitors to improve asset utilisation by reducing reactive power flows and the gains that will come from being able to control load at a feeder level.

There is no redundancy in any of the load control systems. A failure will result in loss of signal until a unit is repaired, i.e. there are no n-1 components in any of the plants. (The forward plan does address this issue.)

Systemic issues leading to the premature replacement of load control plants or parts of them include:

1. *Lack of signal*

   At 725Hz, signal propagation through a distribution network is complex. This frequency sets up many series resonance circuits that absorb the signal and stops receivers working. This resonant frequency issue also stops TLC using capacitors in the distribution network to reduce reactive power flows and improve voltages for greater asset utilisation.

2. *Loss of communication network*

   Sending of automatic load control signals is dependant on the communication network between the master station and individual plants. If the communication network fails, signals cannot be sent.

3. *Failure in load rhythm generator*

   The TLC systems rely on rhythms being generated in local RTUs. From time to time software problems stop these rhythms being generated.

4. *Failure of plant hardware*

   This is normally associated with the older high frequency plants that contain a number of contactors and rotating plant.

5. *Resonance on SWER systems*

   The 725 Hz system causes series resonance to occur on some SWER systems. The amplified ripple signal causes lights to flash off and on, and interferes with other electronic equipment.

6. *Load calculator software and hardware*

   From time to time there are problems with the load calculator software and hardware. These usually occur when software updates are installed or hardware is renewed.

3.3.5.2 Voltage Regulators

Table 3.25 provides information describing location, number of phases, units and age of voltage regulators.

VOLTAGE REGULATORS – DESCRIPTION, UNITS AND VALUE			
Description	**Units**	**Average Age**	**RAB**
Awamate Road 1ph 150 Amp Voltage Regulator	2	3	50,242
Benneydale 1ph 200 Amp Voltage Regulator	2	6	73,919
Bodley Road 1ph 200 Amp Voltage Regulator	2	7	36,376
Burns Street 1ph 300 Amp Voltage Regulator	2		
Kaahu Tee Sub 1ph 150 Amp Voltage Regulator	2	2	48,757
Kopaki 3ph 3 MVA Voltage Regulator	1	51	14,966
Maihiihi 1ph 200 Amp Voltage Regulator	2	5	72,832
Mohakatino 3ph 750 kVA Voltage Regulator	1	51	23,091
Mokai 1ph 150 Amp Voltage Regulator	2	3	86,511
Mokai Geothermal Voltage Regulator 300 Amps	2		
Nihoniho 3ph 1.5 MVA Voltage Regulator	1	47	
Otukou Sub 1ph 60 Amp Voltage Regulator	2	26	38,976
Puketutu 1ph 200 Amp Voltage Regulator	2	5	72,832
Ranganui Road 1ph 100 Amp Voltage Regulator	2	8	113,356
Rangitoto Rd 1ph Voltage Regulator	2		
Scott Road 1ph 200 A Voltage Regulator	2	4	44,519
Soldiers Road 1ph 200 Amp Voltage Regulator	2	12	68,029
Taumatamaire 1ph 200 Amp Voltage Regulator	2	6	73,920
Te Anga 1ph 150 Amp Voltage Regulator	2		56,408
Te Kura Rd 1ph 200 Amp Voltage Regulator	2		
Tirohanga 1ph 150 Amp Voltage Regulator	2	2	40,962
Tuhua 3ph 5MVA Voltage Regulator	1	60	
Turoa Ski Base 1ph 200 Amp Voltage Regulator	3	5	93,954
Waiotaka Sub 1ph 100 Amp Voltage Regulator	2	5	71,175
Whakapapa Tavern 1ph 300 Amp Voltage Regulator	2	7	74,606
Whakapapa Water Tower 1ph 200 Amp Voltage Regulator	2	16	76,154
Whangaehu Valley Road 1ph 200 Amp Voltage Regulator	2	12	122,452
Whatauri Rd 1ph 200 Amp Voltage Regulator	2	1	32,248
Whibley Road 3ph 2MVA Voltage Regulator	1	51	12,828

TABLE 3.25: VOLTAGE REGULATOR SUMMARY

The majority of the sites have two relatively new single phase regulators operating in open delta to give ± 10% regulation. Five older type 3 phase units remain in service. Seven of the regulator sites are at zone substations where regulators are used as a low cost alternative to on load tap-changers built into transformers (Awamate, Kaahu Tee, Nihoniho, Otukou, Tuhua, Waiotaka and Te Anga). One is at a point of supply; necessary for voltage stability.

Figure 3.19 illustrates the regulator age profile.

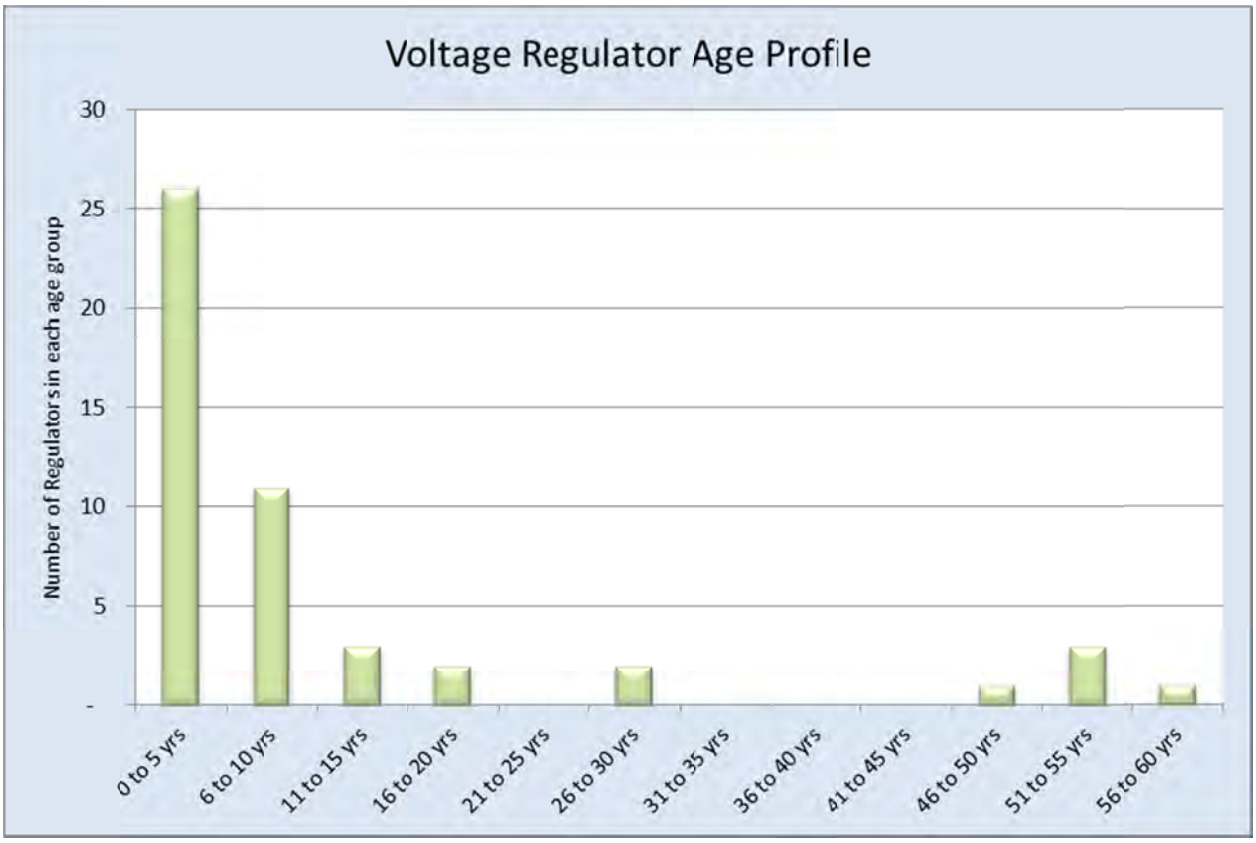


FIGURE 3.19: REGULATOR AGE PROFILES

The renewal programme, the growth that has occurred and the need to ensure compliance with regulations has resulted in the age of the regulator stock reducing substantially. Included in the planning period are allowances for the replacement of the remaining old units and the addition of more regulators in areas where voltage constraints exist or will exist as load increases.

Systemic issues leading to the premature replacement of regulators include:

- Problems with the control relays, particularly the older electro-mechanical systems.
- Problems with software/firmware in modern units.
- The mechanical internal systems sticking and failing.
- Operator error when by-pass switches are closed and units are not in the neutral position.

3.3.5.3 SCADA and Voice Communication

SCADA and load control central system computer uses the Lester Abbey Powerlink product. The system has proven to be reliable and is vital to the operation of the TLC network. For example, it is common during a storm event for more than 150 circuit breaker and other related commands to be issued by the controller. If staff had to be sent to these 150 sites to manually operate equipment, the costs and restoration times would be far greater than those able to be achieved with the use of this system. The system is being constantly renewed to ensure it is maintained in a reliable operating condition.

An indication of the age profile of this equipment is illustrated in Figure 3.20.

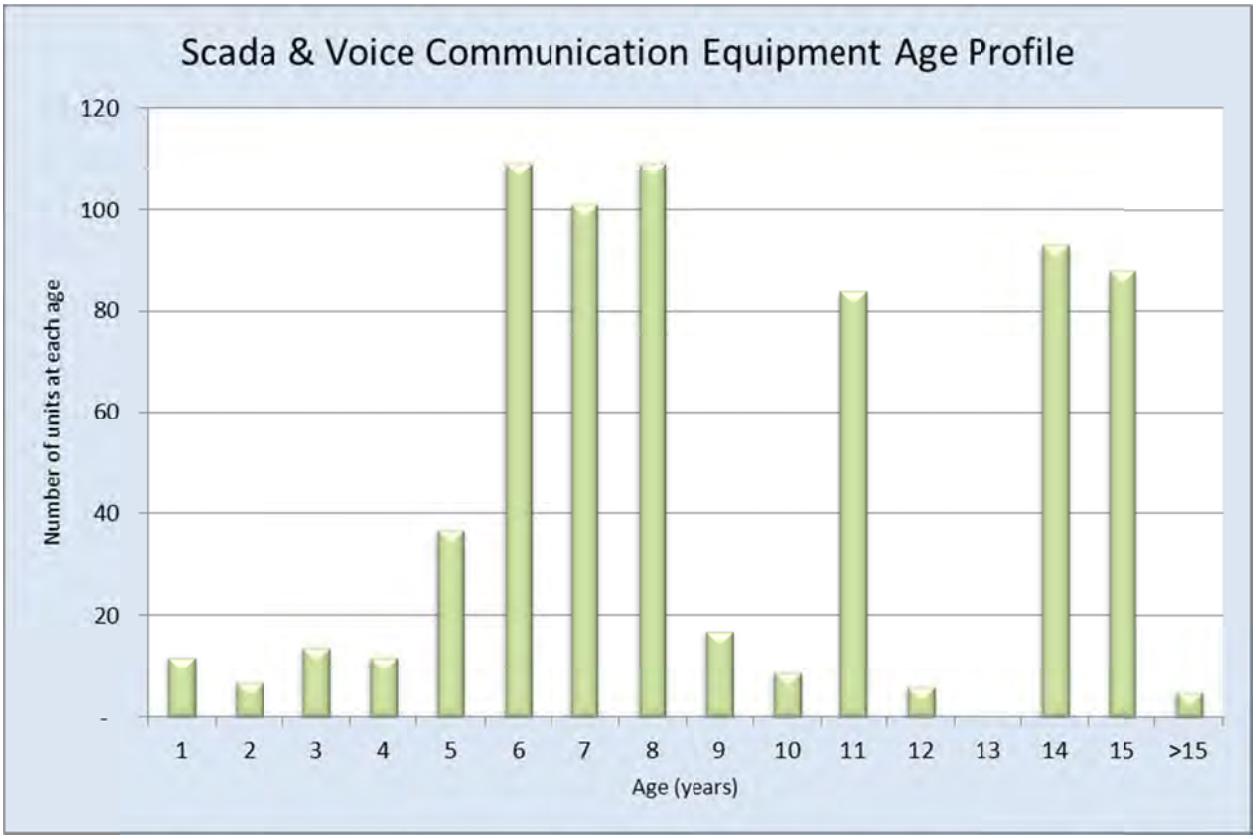


FIGURE 3.20: SCADA AND VOICE COMMUNICATION EQUIPMENT AGE PROFILES

The strategy to renew equipment and keep the technology current will mean no sudden shock to replace the entire system. The system is in good condition.

The SCADA system uses mostly an analogue polled data radio system to communicate with the majority of devices. There are also two links via Leased Direct Circuit (LDC) and two via TLC owned communication lines attached to overhead lines.

The most common issues that cause the system not to operate include:

- Loss of communication.
- Software lockups; is normally related third party equipment.
- Loss of power supplies to RTUs etc.
- Installation configuration errors.

The equipment and system is considered reliable and low cost by industry standards. It is not necessary to employ a dedicated technician or engineering support. An external specialist technician is hired in for about 1 day per month.

The RAB value of SCADA and voice communication equipment is $903,736. This figure includes all SCADA and voice communication componentry and other ancillaries, excluding load control assets.

3.3.5.4 Communication Equipment

3.3.5.4.1 Data Communication

The UHF data communication system consists of a head end and 12 repeater sites (excluding individual RTU radios) operating on two channels. The repeater site locations, radio componentry age, RAB value and condition of this equipment are listed in Table 3.26a. Table 3.26b lists other SCADA and radio communication equipment locations and RAB values. Both tables exclude substation radios.

SCADA REPEATER EQUIPMENT SUMMARY			
Location and Description	**Age**	**RAB**	**Condition**
Mahoe Road: Radio Componentry	4	26,649	Near new
Mahoe Road: Other Ancillaries		11,185	
Motuoapa Reservoir: Radio Componentry	10	3,112	Good operational condition
Motuoapa Reservoir: Other Ancillaries		2,234	
Ohakune: Radio Componentry	7	960	Good operational condition
Ohakune: Other Ancillaries		2,488	
Pomerangi: Radio Componentry	3	20,772	Near new
Pomerangi: Other Ancillaries		15,800	
Pukawa: Radio Componentry	5	22,609	Good operational condition
Pukawa: Other Ancillaries		3,479	
Pukepoto: Radio Componentry	6	12,753	Good operational condition
Pukepoto: Other Ancillaries		4,648	
Ranginui: Radio Componentry	14	8,904	Good operational condition
Ranginui: Other Ancillaries		4,259	
Taumarunui Depot: Radio Componentry	2	2,314	Near new
Taumarunui Depot: Other Ancillaries		2,332	
Tuhua: Radio Componentry	12	47,334	Good operational condition
Tuhua: Other Ancillaries		19,105	
Waipuna: Radio Componentry	7	14,624	Good operational condition
Waipuna: Other Ancillaries		2,628	
Waituhi: Radio Componentry	7	19,239	Good operational condition
Waituhi: SCADA & Radio Communication Equipment		2,258	
Whakaahu: Radio Componentry	8	5,168	Good operational condition
Whakaahu: Other Ancillaries		3,459	

TABLE 3.26A: SCADA REPEATER EQUIPMENT SUMMARY.

OTHER SCADA COMMUNICATION EQUIPMENT			
Location	**RAB**	**Location**	**RAB**
Aria	8,807	Oparure	6,303
Arohena	13,421	Oparure	8,854
Atiamuri	16,224	Otorohanga	3,532
Awakino	4,791	Otukou	8,562
Awamate	12,038	Piopio	4,403
Benneydale	13,573	Piriaka	7,185
Borough	12,679	Piripiri	6,943
Caves	4,770	Pureora	7,601
Chateau	5,136	Rangipo/Hautu	9,541
Gadsby	9,792	Rangitoto	2,922
Gravel Scoop	9,170	Raurimu	3,838
Hangatiki	9,669	Ruapehu Alpine Lifts	5,928
Huirimu	3,532	Southern	3,132
Kaahu	16,053	Taharoa	10,601
KCE Office	4,317	Tangiwai	12,759
Kiko Road	16,368	Taumarunui/Kuratau	773
Kuratau	30,953	Tawhai	8,276
Mahoenui	12,531	Te Waireka	9,578
Maihiihi	7,983	Te Waireka	2,706
Mangapehi	4,463	Tihoi	2,922
Manunui	18,628	Tirohanga	4,451
Maraetai	10,337	TLC Control	1,893
Marotiri	14,955	Tuhua	6,248
Master Station	31,653	Turangi	15,935
McDonalds	3,132	Waiotaka	11,196
Mokau	6,263	Wairere	8,806
National Park	13,878	Waitete	11,558
Nihoniho	10,670	Whakamaru	17,764
Northern	2,568	Wharepapa	4,403
OMYA	3,812	Winstones	2,922

TABLE 3.26B: OTHER SCADA COMMUNICATION EQUIPMENT LOCATION AND RAB.

The data communication network is necessary for system automation. The system is a very simple, slow-speed network focused on circuit breaker and substation automation, not high-speed data and event gathering. It is reliable and has been maintained in good condition.

The age profile indication of this equipment is illustrated in Figure 3.21:

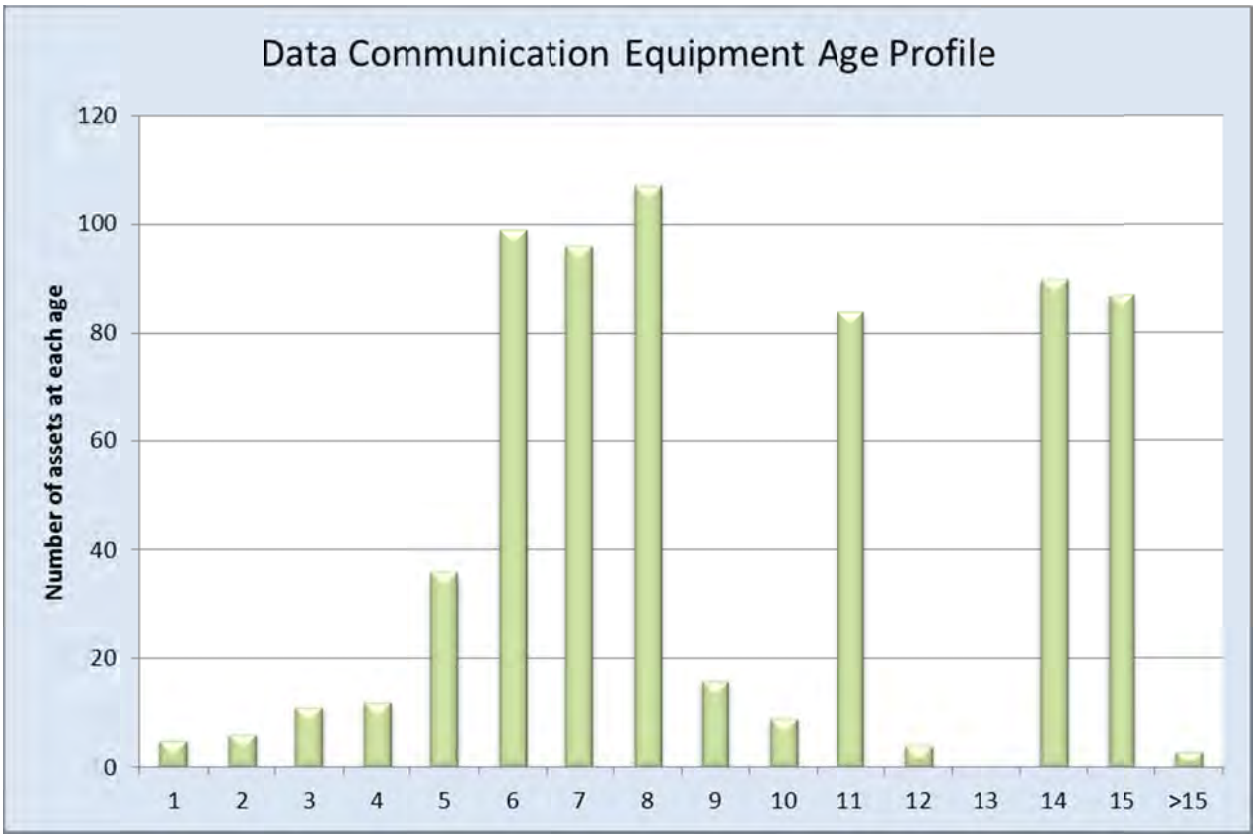


FIGURE 3.21: AGE PROFILE OF DATA COMMUNICATION EQUIPMENT

The age of communication equipment will remain relatively constant during the planning period.

Equipment has been assessed and allowances are included in the Plan for constant renewal of equipment. This means that there will be no sudden shock to replace the entire asset. The renewal programme will result in continual technology upgrade.

Advice from communication specialists is that the system is appropriate and cost effective for the rugged TLC network environment. The existing analogue system will be converted to a low speed digital system over the planning period. Other technologies such as high-speed digital systems would not be as cost effective.

The main causes of failure are external influences such as lightning strikes and the occasional hardware, power supply or software failure.

3.3.5.4.2 Voice Radio Communication Equipment

A frequency modulated voice communication system consisting of six repeaters, linking equipment, and radios in the mobile fleet, are owned and operated by TLC. The location, age of primary radio componentry and condition of this equipment are listed in Table 3.27:

VOICE RADIO COMMUNICATION EQUIPMENT SUMMARY		
Location and Description	**Age**	**RAB**
Maungamangero: Radio Componentry	14	7,469
Maungamangero: Other Ancillaries		1,211
Tuhua: Radio Componentry	12	4,914
Tuhua: Other Ancillaries		9,661
Waipuna: Radio Componentry	7	5,197
Waipuna: Other Ancillaries		364
Pukawa: Radio Componentry	5	5,144
Ranginui: Voice Equipment		9,244
Taumarunui Depot: Voice Equipment		2,981
Te Kuiti Control: Radio Componentry	14	30,676
Te Kuiti Control: Other Ancillaries		4,870
Pukawa: Voice Equipment		364
Taumatamaire: Voice Equipment		10,026
Waituhi: Voice Equipment		8,858

TABLE 3.27: LOCATION, AGE AND CONDITION OF VOICE RADIO EQUIPMENT

The radio repeater sites are necessary for voice communication throughout the region. The use of other communication, such as trunked radio and cell phone equipment is not an option in the King Country because of incomplete coverage.

An age profile indication (years) of this equipment is illustrated in Figure 3.22:

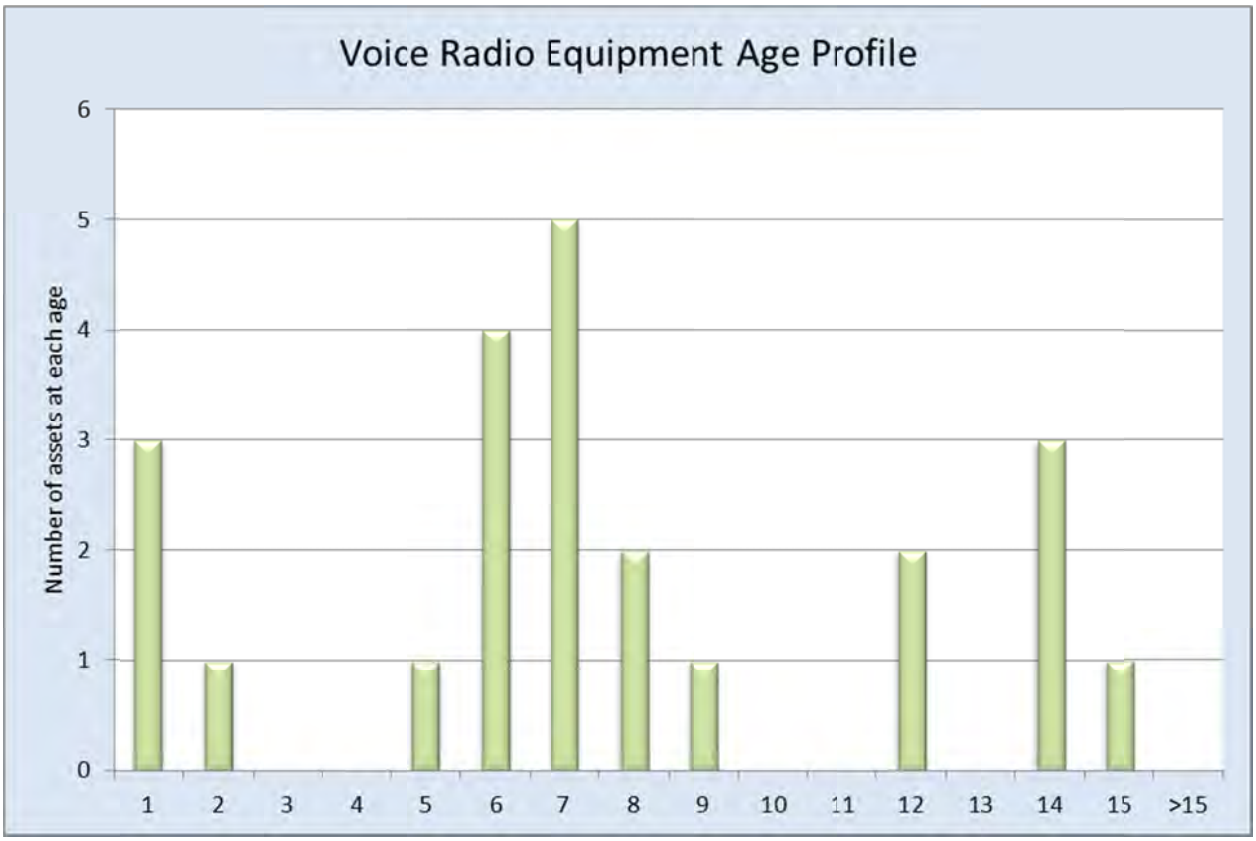


FIGURE 3.22: AGE PROFILE OF VOICE RADIO EQUIPMENT

The overall system is reliable and an extensive maintenance and renewal programme is kept up. Equipment has been assessed and allowances are included in the Plan to renew aged equipment. This ensures there will be no sudden shock to replace the entire radio network. The renewal programme will result in continuous technology upgrades, including a digital voice system with some job dispatch data functionality. TLC has three voice repeater sites that need to be replaced due to the MED (Ministry of Economic Development) requirement to move from 25 kHz to 12.5 kHz wide channels. These upgrades are to be completed by 2014, a year ahead of the 2015 deadline. The main cause of failure of voice radio equipment is external influences such as lightning strikes.

3.3.5.5 Metering systems

The network section of TLC does not own customers' meters. Meters are owned by a subsidiary company. The network however will be required to fund the labour content of the advanced meter rollout that will replace most of the relays that were transferred to the RAB.

The TLC network owns five grid exit point metering installations. The first of these is at the Whakamaru supply site. The equipment includes:

- 33 kV / 110 V potential transformer.
- Metering grade current transformers.
- Half hour meter and remote reading equipment.

The second is at the Tangiwai Winstones Mill interconnection between the mill network and the TLC network.

This equipment includes:

- 11 kV / 110 V potential transformer.
- Metering grade current transformers.
- Half hour meter with remote reading equipment.

The remaining three are associated with the Mokai Energy Park and have only recently been commissioned.

The Whakamaru equipment was installed in 2002 and Tangiwai in 2004. The value of the Whakamaru equipment is included in the value of equipment at this grid exit point. The Tangiwai equipment has a RAB value of $4,035. Figures for the Mokai Energy Park equipment were not available at the time of writing.

Most problems with metering equipment are associated with aged meters and damage to the HV bushings of potential and current transformers and cell phone communication problems.

3.3.5.6 Power factor correction plant

TLC does not own any fixed power factor correction plant. It is focusing on demand side power factor correction. TLC has recently purchased two mobile 1 MVAr 11 kV capacitor banks to be used for voltage support during the use of network alternative feeds. At the time of writing the technical staff are developing intellectual understanding on the use of this equipment.

3.3.5.7 Emergency generator

TLC owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11 kV network during planned and unplanned events. Other sections in this Plan include a description of the equipment. This equipment has a RAB value of $35,251 and was purchased in 2003. Most problems with this equipment are caused by operator error. The equipment is in good condition.

Note: The RAB values used in the above are the latest values that we have been able to source within the timeframes required to produce this document. Most are 2010/11 however one or two may be 2009/10.

3.3.6 Overall Summary

Overall the renewal investment is required in the primary assets: Lines and substations to ensure hazards are controlled and the systems operate reliably. The secondary systems are generally of a newer age and in good condition.

The proceeding sections include considerable specific detail on individual asset categories as required by the disclosure prescription. Table 3.28 summarises this information:

TLC NETWORK – SUMMARY OF AGE AND CONDITION		
Asset Category	**Age Summary**	**Summary Conditions**
Assets at Bulk Supply Points	Mid Age Range	Good operating condition.
Sub-transmission		
Lines	Northern Area: Mid Range	Generally good design and average condition. Most first cycle renewal work is completed and more planned. Lines historically generally tend to have better poles but smaller conductors when compared to the Southern area.
	Southern Area: Older	Under strength design and poor condition in terms of poles. Conductors tend to be larger than the Northern network. Most first cycle renewal work is completed and more planned.
Substation &Transformers	Sites Aging	Older sites need renewal and refurbishment, including transformers and switchgear. Overall substations are in need of on-going renewal.
Distribution Systems		
Lines	Aged Assets	Many assets in need of renewal. Renewal programmes are underway.
Transformers	Average Ages	A number of larger sites have hazard control expenditure needs. Smaller sites; industry typical. Extensive SWER (earthing) systems require additional renewal and maintenance. Plans and programmes are underway to address these needs.
Switchgear	Average to Old Age	Renewal as part of general line renewal. Problems with drop-out fuse connections being addressed by better quality. Renewal plans are in place.
Low Voltage System	Old Age	Many in poor condition and requiring major renewal.
Supporting or Secondary System	Average Age	Good condition.

TABLE 3.28: SUMMARY OF AGE AND CONDITION OF THE TLC NETWORK

It should be noted that the use of high level financial analysis where age is determined by comparing depreciated value to replacement value does not give a good overall picture of TLC's asset renewal needs. Maintenance and targeted renewal are extending asset lives to greater than those indicated by using this comparison.

3.3.7 Justification of Assets

The Sub-transmission and distribution systems operated by TLC have been developed over the years to meet activities of the regions and the electricity needs of customers. As a general comment, the region covered by TLC has more of a lack of assets than overbuild.

Electricity was reticulated to the King Country at the lowest possible cost through the extensive use of innovative methods such as Single Wire Earth Return reticulation. For many years, supply to isolated areas was from local small hydro generators remote from any grid exit point connections. Other areas were developed for construction, forestry, mining, and mountain communities. All were reticulated using technologies and engineering solutions to meet the needs of the times.

This history and development pattern of the local regions is the reason why many of the assets exist and are where they are today. As time has gone on the originally installed assets have continually been modified to meet the needs of the various communities. TLC assets have not generally been subject to the effects of the property booms like other areas in the country. Therefore, equipment has not been replaced as part of growth upgrades.

Some of the community changes have been significant; for example, Turangi has changed from a large construction community into a tourist, holiday, and prison support town. In the rural areas there has been both farm rationalisation and dairying development taking place.

Because of the history, there are examples where assets do not comply with present day technical, engineering, and industry codes, although they would have been built to the requirements at the time of construction. It was usual for regulation and code changes to permit existing assets to remain, legally, in use until replaced.

As discussed in other sections plans are underway to replace legacy equipment that does not comply with present day hazard control expectations. The rugged terrain, remote farming communities, and commercial development will have a continued bearing on asset configuration and the cost of operation.

Productive land use in the King Country is reliant on the regular applications of fertiliser, often by planes and helicopters. Some of this fertiliser is not only corrosive but also relatively conductive when mixed with water. The consequence of this is that hardware must be of the more expensive pollution-resistant type.

The RAB valuation did not include any optimisation of assets except that of SWER isolation transformers. These were optimised out to bring the valuation of SWER lines into line with two wire systems as allowed under the 2004 ODV valuation rules.

3.3.8 Justification for Sub-transmission Assets

3.3.8.1 Connection/supply points

As outlined previously, the network consists of three 33 kV regions (North Western, North East (River) and Central) and an 11 kV region directly connected to a grid exit point (Ohakune). The justification for each of these grid exit points is as follows:

3.3.8.2 North Western (Hangatiki)

The Hangatiki GXP provides capacity to the region that could not be served at 33 kV or 11 kV, as it is 54km as the crow flies from the Ongarue GXP and 58km from the Whakamaru connection point.

Physically, some very rugged country separates Ongarue and Hangatiki, and the Rangitoto Mountain Range and the Pureora Forest separates Whakamaru and Hangatiki. The system load (sum of distributed generation and Grid Exit import) is over 30 MVA.

At times, depending on the availability of generation and industrial consumption, demand at this grid exit point fluctuates between almost zero (400 kVA) and over 30 MVA. Industrial customers, especially the Taharoa Iron Sands ship loading 50km to the west, have the biggest influence on demand. Given the distances involved and the loads, the grid exit point assets would be difficult to eliminate.

3.3.8.3 North Western (River) (Whakamaru and Atiamuri)

The Whakamaru supply point, in addition to being 58km from Hangatiki, is 65km from Ongarue across the Pureora Forest Park and mountain range. Atiamuri is a backup supply for this area and this is operated at times in a complex arrangement.

There is currently little industrial load in this region; however, it is expected that more will be attracted, particularly around the Mokai geothermal complex. Mangakino and Whakamaru villages are the only closely settled areas. Most of the load is rural and associated with dairy farming. This creates daily and seasonal peaks.

The recently commissioned Energy Park supply is also in this area. This supply connects directly to the Mokai geothermal plant and is necessary to supply the energy intensive industries in the park. The park is located about 20 km from Whakamaru, and as such taking a 10 MVA supply from the adjacent geothermal generation is much more cost effective than constructing/upgrading lines over this distance. Supply is also much more reliable and secure than it would be on a single spur type set up.

3.3.8.4 Central

The GXPs supplying this network are Ongarue, National Park, and Tokaanu. The distances involved, loadings connected distributed generation, and conductor sizes justify these GXPs. For example, Ongarue to Tokaanu is 72km, Tokaanu to National Park is 68km, and National Park to Ongarue is approximately 60km.

3.3.8.5 Ohakune

The Ohakune region is isolated from the rest of the TLC network by Mt Ruapehu. The area has a single shared GXP supplying the region at 11 kV (the grid exit point is shared with Powerco for its customers at Raetihi). A very light load backup supply is available from the Winstone Pulp Mill 11 kV network at Karioi.

The customers in the region have funded this low-load backup link. This has insufficient capacity for the operation of the Turoa Ski Field and is only used outside of the ski season.

The major activities in the area are the ski field, its related accommodation, and carrot processing. Some relatively large scale dairying has been established in recent times.

3.3.8.6 Justification for sub-transmission 33 kV lines

The justification for the use of 33 kV Sub-transmission is the product of the kVA x km, as even though the loads are often light, the distances are usually large. Table 3.29 prescribes the use of the line and from this, the justification has been deduced and summarised.

USE AND JUSTIFICATION OF 33 KV LINE ASSETS			
Asset	**Use: Present and likely at the end of the planning period**	**Justified**	**Able to be replaced with a smaller capacity asset?**
Gadsby / Wairere 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Gadsby Rd 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Lake Taupo 33	Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations.	Yes	No
Mahoenui 33	Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. DG resource exists in the area is under investigation.	Yes	No
National Park / Kuratau 33	Interconnecting line between the National Park GXP and Kuratau marshalling site. Normal load on line is the Whakapapa ski field and Central Plateau rural area including supply to the Whanganui diversion race controls.	Yes	No
National Park 33	Short length of spur line connecting National Park GXP to zone substation.	Yes	No
Nihoniho 33	Spur line connecting Ongarue GXP to Nihoniho zone substation.	Yes	No
Ongarue / Taumarunui 33	Main line supplying Taumarunui from the Ongarue GXP.	Yes	No
Taharoa A 33	Supply to iron sand extraction at Taharoa and future DG sites (West Coast Wind and Hydro) (Customer requested and funded. Some local rural supply also.	Yes	No
Taharoa B 33	Supply to iron sand extraction Taharoa and future DG sites. (West Coast Wind and Hydro - Customer requested and funded). Some local rural supply also.	Yes	No
Taumarunui / Kuratau 33	Interconnecting line between the Ongarue GXP and the Kuratau marshalling site. Normally loaded with output of Kuratau area DG back into the Ongarue GXP. If Kuratau DG did not exist or was not paying a fair portion of this line, options for continuing renewal, maintenance and ownership will need further evaluation.	Yes	No
Te Kawa St 33	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	Yes	No
Te Waireka Rd 33	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	Yes	No
Tokaanu / Kuratau 33	Interconnecting line between the Tokaanu GXP and Kuratau marshalling site. Normally supplies Kuratau zone sub and is a backup for the connection of the Kuratau area DG to the grid. Also used to back up National Park and Ongarue.	Yes	No

USE AND JUSTIFICATION OF 33 KV LINE ASSETS			
Asset	**Use: Present and likely at the end of the planning period**	**Justified**	**Able to be replaced with a smaller capacity asset?**
Tuhua 33	Few metres of spur line connecting Ongarue GXP to Tuhua zone substation.	Yes	No
Turangi 33	Spur line connecting Tokaanu GXP to the Turangi zone substation.	Yes	No
Waitete 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Whakamaru 33	Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu and Marotiri zone substations.	Yes	No

TABLE 3.29: USE AND JUSTIFICATION OF 33 KV LINE ASSETS

3.3.8.7 Justification for zone substation assets

The zone substation assets are sprinkled through a large, sparsely populated area. All sites are justified and removing any would create problems with maintaining statutory voltages, customers' reliability expectations and supplying existing loads.

Table 3.30 summarises the justification for the zone substation assets:

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Arohena	Supply to Arohena dairying area.	Well-loaded 3 MVA single unit substation supplying the dairying area around Arohena and Wharepapa. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Atiamuri	Step up site for alternative supply to Whakamaru area.	Single unit connecting 33 kV network to 11 kV generation bus at Atiamuri. The site forms part of the Mighty River Power Atiamuri site. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single outgoing 33 kV breaker and an 11 kV circuit breaker onto the Mighty River Power generation busbar. It would be difficult to rationalise this with a more cost-effective configuration.
Awamate Road	Supply to part of Turangi	Container substation with 2 MVA transformer backs up the Turangi substation and supplies local area. The configuration is low cost and it would be difficult to rationalise with a more cost effective arrangement.
Borough	Main supply to Taumarunui.	Two-unit site supplying the majority of Taumarunui and the surrounding rural areas. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with the grid exit point circuit breaker at Ongarue providing incoming protection via a fault thrower, earthing switch at the substation. There are two incoming circuit breakers and a single 11 kV busbar with six outgoing circuit breakers. It would be difficult to rationalise this with a more cost-effective configuration. It would ideally warrant a more complex and expensive arrangement.
Gadsby Road	Supply to North end of Te Kuiti.	Single unit with the primary loads being the north end of Te Kuiti; saw milling, dairying and a large rural dry stock area to the west of Te Kuiti. Load is growing on this site, principally caused by the expansion of industrials. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple with a single 11 kV bus and three outgoing circuit breakers. It would be difficult to rationalise this with a more cost-effective configuration.
Hangatiki	Supply to Waitomo Caves area.	Single unit with the primary loads being the Waitomo Caves tourist area, limestone processing, and dairying. The substation is located adjacent to the Hangatiki grid exit point. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple with the grid exit point 33 kV breaker responsible for isolating the 33 kV and a simple single indoor bus arrangement for the 11 kV with two outgoing circuits. It would be difficult to rationalise this with a more cost-effective configuration.
Kaahu Tee	Supply to part of Marotiri area	Installed to reduce loading on Marotiri and bring loading back to within transformer rating. Also assists in overcoming voltage problems in area. A more cost effective network would not result if the substation were eliminated or reduced in voltage. The configuration is low cost and it would be difficult to rationalise this with a more cost effective configuration.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Kiko Road	Supply to the Eastern side of Lake Taupo.	3 MVA single unit substation supplying Eastern side of Lake Taupo. Holiday loadings in this area have been increasing and are continuing to grow. A more cost-effective network would not result if the substation were eliminated or reduced in voltage The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Kuratau	Supply to the rural area at the South end of Lake Taupo including surrounding rural area.	Single unit substation and major 33 kV switching point on TLC network. It is the junction point between 33 kV lines coming from three grid exit points and the injection site for the 6 MVA Kuratau distributed generation plant. The zone substation provides supply to the local rural area including most of the West Taupo area and the holiday areas including Kuratau and Omori. The number of residences in this area continues to grow. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration of the 33 kV marshalling area and the zone substation is relatively simple. It would be difficult to replace it with a more cost-effective design.
Mahoenui	Supply to Mokau, Awakino, Tongaporutu, and remote rural areas inland.	Small simple site supplying surrounding rural area and long 11 kV line down through the Awakino Gorge and the rural settlements of Awakino, Mokau, and Tongaporutu. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Manunui	Supply to rural area South of Taumarunui.	Single unit substation approximately 6.5km south of Taumarunui town. It is an injection point into the 33 kV network for the output of the Piriaka distributed generation plant. Plans are included in the planning period to increase the 11kV transfer capacity from this site back in to Taumarunui, given that the main Taumarunui substation (Borough) has been identified as a high risk of flooding site. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with one incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design. If anything, an additional circuit breaker could be warranted.
Maraetai	Supply to Whakamaru area.	Single unit site supplying the Whakamaru and Mangakino villages, surrounding dairy areas and local service supplies to four Mighty River Power Waikato hydro sites. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple 11 kV bus supplying eight outgoing circuits. There is an incoming 33 kV breaker, outgoing 11 kV breaker and two bus section isolators. The switchgear is ground-mounted outdoor equipment and it would be difficult to rationalise this with a more cost-effective configuration. A more complex arrangement could be warranted.
Marotiri	Supply to Mokai and west Taupo area.	Well-loaded 3 MVA single unit substation supplying the dairying, lifestyle, and horticulture areas of Marotiri, Mokai, and Tihoi. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design. If anything, an additional circuit breaker could be warranted.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
National Park	Supply to National Park village and surrounding rural area.	Single unit supplying National Park village. Load gets up to about 2 MVA during winter when accommodation is full. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Nihoniho	Supply to Ohura and surrounding large rugged remote idea.	Small site: 15km from point of supply in rugged terrain. Substation cannot be eliminated if load at end of planning period is to be supplied. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single transformer and separate regulator. It would be difficult to replace it with a more cost-effective design.
Otukou	Supply to rural Otukou and Outdoor Pursuits Centre.	Small site: Would require the reconstruction of 15.2km of conjoint 33/11 kV line. Existing 33 kV line would have to be totally rebuilt for this distance, as present poles are very low. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single outdoor overhead busbar. It would be difficult to replace it with a more cost-effective design.
Piripiri / Te Anga	Supply to Te Anga and Marokopa	Small site supplying coastal area including the Southern side of Kawhia harbour. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. (The site has recently been relocated to facilitate the more economic connection of a 2 MVA distributed generation scheme at Speedys Road.) The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Taharoa	Supply to Iron Sand processing and ship loading.	A three-unit site set up to supply the Taharoa iron sand extraction plant. The site has (n-1) capacity. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single 11 kV bus bar and 12 outgoing circuits. It would be difficult to rationalise this with a more cost-effective configuration.
Tawhai	Supply to Whakapapa village and ski area.	Single unit with the primary load being the Whakapapa Ski Field and village. Present loads and plans for the ski field are starting to push this site and will push it further in the future. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple, with single 33 kV incoming and 11 kV outgoing breakers plus a 33 kV line breaker looking at the forward and reverse protection of the outgoing 33 kV line. It would be difficult to rationalise this with a more cost-effective configuration. It would be easy to warrant a more expensive solution.
Te Waireka	Supply to Otorohanga.	Two unit site supplying Otorohanga and surrounding rural areas. A (n-1) transformer capacity is available. A more cost effective network would not result if the substation were eliminated or reduced in voltage. There are two incomers and four outgoing circuits of a single 11 kV bus. It would be difficult to rationalise this with a more cost-effective configuration.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Tokaanu	Supply to Tokaanu village.	Small site supplying Tokaanu town. In an ideal "green fields" situation the architecture of this area would be different. This is, however, not possible given that lines would have to be constructed over some very sensitive Maori land. The probability of achieving this is virtually zero. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration at the site is very simple with a single 33 kV circuit breaker and ring main used for 11 kV switchgear. It would not be possible to replace it with a more cost-effective design.
Tuhua	Supply to rugged remote rural area around Tuhua.	Small site next to the Ongarue point of supply. Cannot be eliminated if supply to areas north of Taumarunui such as Ongarue is to be maintained given the supply from the grid exit point at 33 kV. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single transformer and separate regulator. It would be difficult to replace it with a more cost-effective design.
Turangi	Supply to Turangi town.	Two unit site supplying Turangi and surrounding rural areas. Backup supply was put into place a few years ago to allow the site to be removed from service and hazard minimisation/elimination projects to be completed. Without this backup n-1 capacity and security was not available to Turangi. A more cost-effective solution would not result if the substation were eliminated or reduced in voltage. The configuration is simple with the remote 33 kV breaker used for 33 kV isolation and an outdoor overhead 11 kV bus with two outgoing circuit breakers. It would be difficult to rationalise this with a more cost-effective configuration.
Waiotaka	Supply to Hautu Prison	Container substation with 1.5/1.8 MVA transformer. Funded principally by the Corrections Department. The configuration is low cost and it would be difficult to rationalise this with a more cost effective configuration. The unit also provides about 50% of the backup for Turangi.
Wairere	Supply to Piopio and DG connections.	Two-unit site and injection point for 6.2 MVA of generation from the Wairere and Mokauiti distributed generation stations. The five outgoing rural feeders head off in different directions into the central King Country. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. Relatively complex site with distributed generation and load control connected to 33 and 11 kV bus bars. The 33 kV configuration consists of a double bus and the 11 kV is interconnected outdoor and indoor arrangement. It would be difficult to rationalise this with a more cost-effective configuration.
Waitete	Supply to majority of Te Kuiti and surrounding rural area.	Three-unit site supplying majority of Te Kuiti and surrounding rural areas. A big portion of the load from this site is the Te Kuiti industrial area consisting of a number of industries including a sawmill, and two meat-processing plants. A more cost-effective network would not result if the substation were eliminated or reduced in voltage.

TABLE 3.30: JUSTIFICATION FOR ZONE SUBSTATIONS

3.3.8.8 Justification for Zone Substation Transformers

Detailed in Table 3.31 is the justification for transformer sizing at zone substations.

JUSTIFICATION FOR TRANSFORMER SIZING AT ZONE SUBSTATIONS			
Site	**Existing Transformer Size (MVA)**	**Present Loading (MVA)**	**Comment**
Arohena	1 x 3	2.10	New transformer supplying dairying area.
Atiamuri	1 x 10	8.57	Step up transformer for complex river system.
Awamate Road	1 x 2	1.00	New transformer backing up Turangi.
Borough	2 x 5	7.40	Old transformers supplying Taumarunui.
Gadsby Road	1 x 5	4.93	Refurbished transformer supplying industrial load.
Hangatiki	1 x 5	4.10	Modern transformer supplying mostly industrial load.
Kaahu Tee	1 x 2.4	1.40	New transformer backing up Arohena.
Kiko Road	1 x 3	1.40	Area has increasing holiday home load.
Kuratau	1 x 3, 1 x 1.5	2.80	Old transformer supplying holiday area. New transformer to support load to growth area.
Mahoenui	1 x 3	1.30	Old transformer in remote area.
Manunui	1 x 5	2.20	Old transformer supplying declining area. Provides DG connection.
Maraetai	1 x 5	4.60	New transformer supplying dairy area.
Marotiri	1 x 3	2.60	Additional site to reduce load established. (Kaahu Tee).
National Park	1 x 3	2.20	Old transformer supplying holiday area.
Nihoniho	1 x 1.5	0.93	New transformer is on order after original unit (1.5MVA) destroyed by lightning). To be installed by year end.
Oparure	1 x 3	2.00	Modern transformer supplying industrial load.
Otukou	1 x .5	0.50	Remote area.
Taharoa	3 x 5 (Customer requested reliability)	10.10	1970's transformers supplying industrial load.
Tawhai	1 x 5	5.20	Old transformer supplying Whakapapa.
Te Anga	1 x 1.5	0.90	DG in area has recently reduced load.
Te Waireka	2 x 10	14.16	Modern transformers supplying Otorohanga.
Tokaanu	1 x 1.125	0.45	Old transformer.
Tuhua	1 x 1.5	0.93	Old transformer in remote area.
Turangi	2 x 5	4.30	Old transformers supplying Turangi.
Waiotaka	1 x 1.5/1.8	0.50	New transformer supplying correctional facility.
Wairere	2 x 2.5	4.36	Connects Wairere Falls generation.
Waitete	3 x 5	9.00	Old transformers supplying Te Kuiti.

TABLE 3.31: JUSTIFICATION FOR TRANSFORMER SIZING AT ZONE SUBSTATIONS

3.3.9 Justification for Distribution Feeders

Table 3.32 provides justification details on each of the 11 kV feeders:

11 kV FEEDER JUSTIFICATION						
Feeder	**Present Load (a)**	**Max Fault Level (3-phase symmetrical kV)**	**Conductor Range**		**Feeder Length (km)**	**Comments**
			Max	**Min**		
NORTHERN AREA						
Aria	25	3.32	Mink	Squirrel	78	Long rural feeder with dairying and SWER lines. Conductor size required for volt drop.
Benneydale	240	3.25	Dingo	7/064 Cu	134	Long feeder with industrial, rural and distributed generation load. Larger conductor sizes could easily be justified as it has four regulators in series.
Caves	42	3.78	Mink	7/064 Cu	65	Conductor size needed for voltage drop and backup current loading.
Gravel Scoop	99	6.54	Mink	Squirrel	95	Long feeder with dairying load.
Hangatiki East	156	3.78	Mink	7/064 Cu	20	Conductor size required for load and voltage drop (fully loaded).
Huirimu	27	1.55	Ferret	Squirrel	45	Rural feeder. Backup for Pureora feeder.
Mahoenui	24	3.32	Mink	Squirrel	108	Rural and backup for Mahoenui sub. Conductor size is adequate for purpose.
Maihiihi	173	6.54	Mink	Squirrel	103	Urban and rural feeder. Well loaded. Has two regulators in series. (Will need strengthening during planning period, included in estimates).
Mangakino	34	3.11	Mink	Squirrel	23	Supply to Mangakino town. Conductor size for supplying neighbouring dairying load.
McDonalds	139	6.54	Mink	Squirrel	38	Feeder supplying industrial and dairying load.
Mokauiti	45	3.32	Mink	Squirrel	74	Long rural feeder with SWER lines. Conductor size required for volt drop.
Oparure	81	3.1	Mink	Squirrel	81	Partly urban and rural feeder. Used in emergencies to start and synchronise Wairere generation. Also has some industrial load.
Otorohanga	136	6.54	Mink	Squirrel	53	Urban and rural load. Supplies Otorohanga CBD, residential and some industrial areas. Not possible to reduce conductor sizes.
Piopio	58	3.32	Mink	Squirrel	55	Rural feeder and supply to Piopio town. Conductor size required for volt drop.

11 kV FEEDER JUSTIFICATION						
Feeder	**Present Load (a)**	**Max Fault Level (3-phase symmetrical kV)**	**Conductor Range**		**Feeder Length (km)**	**Comments**
			Max	**Min**		
Pureora	89	3.11	Mink	Squirrel	52	Long rural feeder supplying dairying and industrial load. Has two regulators (a further two regulators and some re-conductoring have been included in planning period estimates. Dependent on customer load increases).
Rangitoto	128	5.08	Mink	Flounder	77	Industrial and rural feeder that can be paralleled to others. Could warrant larger conductor due to industrial load.
Te Kuiti South	60	5.08	7/083 Cu	7/064 Cu	41	Partly urban and rural feeder. Used in emergencies to start and synchronise Wairere generation. Could justify larger rather than smaller conductor size.
Te Kuiti Town	73	5.08	7/083 Cu	7/064 Cu	2	Supplies CBD and links to other feeders.
Te Mapara	16	3.32	Mink	Squirrel	63	Rural feeder with SWER lines. Conductor size required for volt drop.
Waitomo	111	3.1	Mink	Squirrel	12	Partly urban and rural feeder.
Whakamaru	73	3.11	Mink	Squirrel	69	Rural feeder supplying dairying load and villages. Dependent on customer load increases.
Wharepapa	71	1.55	Ferret	Squirrel	106	Long rural feeder supplying dairying load. Links into Maihiihi feeder to provide a backup for Arohena area.
SOUTHERN AREA						
Awamate	40	1.63	Flounder		7	Urban and rural feeder. SWER systems connected.
Chateau	254	2.62	Mink	Flounder	29	Supplies large load on ski fields.
Coast	16	1.28	7/16 Cu	Mullet	84	Rural feeder supplying coastal settlements. SWER systems and distributed generation connected.
Hakiaha	87	5.08	7/16 Cu		6	Supplies industrial CBD of Taumarunui. Conductor size adequate.
Kuratau	75	3.06	Ferret	Squirrel	38	Supplies holiday homes and rural area. Comes under pressure due to voltage drop during holiday periods. SWER systems connected.
Manunui	57	3.29	Mink	Flounder	85	Rural and urban area. Links with two Taumarunui feeders for backup. Conductor sizes marginally adequate. SWER systems connected.
Matapuna	102	5.08	7/16 Cu	Flounder	17	Urban and rural feeder.
Mokai	99	1.97	Ferret	Flounder	76	Long rural feeder and backup supply for Tihoi feeder. Growth are with dairying and lifestyle blocks and geothermal development.

11 kV FEEDER JUSTIFICATION						
Feeder	**Present Load (a)**	**Max Fault Level (3-phase symmetrical kV)**	**Conductor Range**		**Feeder Length (km)**	**Comments**
			Max	**Min**		
Mokau	50	1.27	Mink	Squirrel	131	Long rural feeder with coastal holiday settlements. SWER systems connected. Conductor size required for voltage drop. The feeder has two regulator sites for voltage support.
Motuoapa	26	2.31	Mink	Flounder	2	Supplies rural area hand holiday homes around Lake Taupo. Conductor size needed for construction strength.
National Park	42	2.12	Mink	Flounder	45	Rural and urban feeder. Conductor sizes marginally adequate.
Nihoniho	28	1.22	Ferret	Flounder	30	Rural feeder. SWER systems connected.
Northern	114	5.08	Dog	Flounder	124	Urban and rural feeder. SWER systems connected. Conductor size required for loading and voltage drop.
Ohakune	94	5.84	Dog	Squirrel	13	Urban and rural feeder. Supplies bulk of Ohakune CBD. Peaks during ski season. Has inadequate conductor size in some locations for physical snow and electrical loadings.
Ohura	27	1.22	Ferret	Flounder	182	Rural feeder. SWER systems connected.
Ongarue	20	1.33	Ferret	Flounder	122	Extensive rural feeder with a large number of SWER lines.
Otukou	14	0.59	Ferret	Flounder	6	Small rural feeder.
Oruatua	33	2.31	Mink	Flounder	91	Growth area, supplies a number of lake front holiday homes with fluctuating demand. Conductor sizes are required for peak loading.
Rangipo/Hautu	123	6.5	Mink	Flounder	42	Supplies part of Turangi town and both prisons, plus SWER on end of feeder. Mink required for load and voltage drop.
Raurimu	33	2.12	Mink	Flounder	171	Rural feeder with long SWER systems connected. Conductor sizes marginally adequate.
Rural	5	2.88	Flounder	Mullet	6	Remote rural feeder supplying Taharoa village and surrounding area.
Southern	42	3.29	Dog	Flounder	124	Rural feeder. Links with National Park. Conductor sizes marginally adequate. SWER systems connected.
Tangiwai	70	5.84	Dog	Flounder	91	Supplies part of Ohakune town and a large rural area. Backup supply from Winstones POS.
Tirohanga	58	1.81	Ferret	Squirrel	77	Supply rural dairying area. Conductor size needed for voltage drop. Has one regulator in series.

11 kV FEEDER JUSTIFICATION						
Feeder	**Present Load (a)**	**Max Fault Level (3-phase symmetrical kV)**	**Conductor Range**		**Feeder Length (km)**	**Comments**
			Max	**Min**		
Tihoi	47	1.97	Mink	Squirrel	62	Long rural feeder and backup supply for Whakamaru feeder. Growth area with dairying.
Tokaanu	17	1.36	3 Core 35mm cable		1	Supply to Tokaanu town.
Turoa	102	5.84	Dog	Flounder	60	Supplies ski field, urban and rural areas. Has 3 regulators in series. A further regulator will be needed during planning period. Conductor is marginally adequate.
Tuhua	25	1.33	Ferret	Flounder	41	Extensive rural feeder with a large number of SWER lines.
Turangi	69	6.5	Mink	Flounder	9	From substation to underground reticulation supplying the CBD and most of the residential area.
Waihaha	28	3.06	Flounder		116	Supplies holiday homes and rural area. SWER systems connected.
Waiotaka	11	1.23	Ferret	Flounder	10	Supplies Hautu Prison complex. Back up for Rangipo/Hautu.
Western	47	5.08	Mink	Flounder	137	Urban and rural feeder. SWER systems connected. Conductor size required for loading and voltage drop.

TABLE 3.32: 11 KV FEEDER JUSTIFICATION

3.3.10 Justification for Distribution Voltage Control Devices

The supply from 33 kV grid exit points is unregulated and generally complies with the electricity participation codes. To supply customers with the range of voltage as specified by the electricity regulations, closer voltage control is required at the zone substation level. Consequently, there is a need to have voltage control equipment at the zone substation level. Many of the feeders are also of considerable length and there is a need for voltage control devices along these. Distributed generation adds complexity to voltage control schemes and, in the future, it is likely that a greater bucking range will be needed in some areas. The voltage control devices generally used at zone substations provide a 5% buck to a 15% boost. Line regulators generally have a ±10% buck and boost range.

The amount of distributed generation, the length of many of the TLC feeders and the sub-transmission network mean that most voltage control devices are operated across the entire tapping range. There are areas, mostly towards the extremities, of the TLC network where voltages are outside of the limits of the regulations.

All zone substation tap changers are automatic. Modular substations use line regulators in series with simple fixed tap transformers. Table 3.33 provides the details on justification for the TLC 11 kV network regulators.

VOLTAGE REGULATOR JUSTIFICATION	
Location and Regulator Sites	**Reasons for Need**
Awamate Rd Zone Substation 1 site	Part of a modular zone substation that controls voltage to Turangi town.
Benneydale Feeder 4 sites	Lengthy feeder with rural, distributed generation and industrial load. Regulator is working through most of buck and boost range depending on what distributed generation and load are doing. Working in series with Benneydale 1, 2 and 4.
Chateau Feeder 2 sites	Regulator is controlling voltage to Whakapapa ski area . Regulator is working through most of boost range. Lifts, snow making equipment and ski lodges can vary the load dramatically.
Kaahu Tee Zone Substation 1 site	Part of the modular Kaahu Tee substation. Used to boost voltage in dairying and lifestyle subdivision.
Maihiihi Feeder 2 sites	Long 11kv feeder supplying dairying area . Regulator is working through most of boost range to compensate for feeder conductor size.
McDonalds Feeder 1 site	11 kV feeder with large limestone processing plant and dairying load.
Mokau Feeder 2 sites	Long feeder supplying holiday areas of Mokau and Tongaporutu. Regulator is working through most of boost range due to length of feeder and conductor size.
Mokai Feeder 1 site	Heavily loaded dairy area. Forms part of the back up power supply to Mokai Energy Park.
Miraka Feeder 1 site	Supply to the Mokai Energy Park from an unregulated Mokai geothermal station supply to a regulated supply to dairy factory and surrounding customers.
Nihoniho Zone Substation 1 site	Regulates 11 kV from fixed tap transformer. Supplies a largely rural/farming area.
Otukou Zone Substation 1 site	Fixed tap transformer requires regulation on to the 11 kV network.
Pureora Feeder 2 sites	Long feeder with meat processing plant and dairying load. Regulator is towards and looking after meat plant and dairying load. Unit is operating full boost range. Another regulator site could be justified on this feeder.

VOLTAGE REGULATOR JUSTIFICATION	
Location and Regulator Sites	**Reasons for Need**
Tangiwai Feeder 1 site	11 kV long feeder that is used as a backup supply to Ohakune town and the Karioi pulp mill during Transpower shutdowns of the Ohakune point of supply. Regulators run full boost range.
Te Anga Zone Substation 1 site	Te Anga voltage regulators are a part of a modular zone substation. 150 Amps rated. The advanced controller was required to cope with distributed generation and reverse power flows through the zone substation.
Tirohanga Feeder 1 site	Used to boost voltage to Forest Road area dairy conversions. The need for regulation is due to a legacy issue of small wire sizes in the area.
Tuhua Zone Substation 1 site	Regulates 11 kV from fixed tap transformer. Supplies a largely rural/farming area.
Turoa Feeder 3 sites	Heavy wintertime loading on this feeder requires it to be voltage boosted and regulated mainly due to ski fields and holiday homes used during winter.
Waiotaka Zone Substation 1 site	Part of the modular zone substation serving the prison and surrounding area. Fixed tap transformer.
Wharepapa Feeder 1 site	11 kV feeder to predominately dairying area with traditional peak morning and night loads.

TABLE 3.33: JUSTIFICATION FOR VOLTAGE REGULATORS

3.3.11 Justification for Reactive Compensators

TLC does not own any fixed reactive compensators. Two mobile 1 MVAr 11 kV capacitor banks are being commissioned for network support. They are justified by the need to have generators of similar capacity to provide reactive power when the network is in an abnormal condition. The cost of a generator as compared to a static capacitor providing reactive power is several factors more expensive.

3.3.12 Justification for Distribution Transformers

Within practical limits TLC distribution transformers are well utilised. The main driver to ensure utilisation is the structure of line charges. As stated in other sections, TLC charges are based on three principal components: capacity, peak and dedicated asset charges. (Customers who are supplied by a transformer that supplies three, or less, customers incur dedicated asset charges.)

This structure means customers who have nominated excessive transformer capacity or size are penalised through charges. Transformer capacity and the amount customers are paying for, and require, are regularly reconciled. This approach results in few stranded oversize transformers on the network that are not installed to meet customers' requests.

3.3.13 Justification for Low Voltage

Most of TLC's low voltage network is overhead. What underground network there is tends to be under-engineered by industry standards. For example, there are rarely links between circuits or substations. As a short-term reliability fix TLC has a mobile generator it uses to provide supply when failures occur in large low voltage cables or spur 11 kV supplies to transformers. Table 3.34 lists the areas where underground low voltage distribution exists, the justification for it and comments on the engineering standard it meets.

LOW VOLTAGE NETWORK JUSTIFICATION		
Area of LV	**Justification**	**Engineering Standard**
Taharoa village	Most cost-efficient way of achieving reticulation originally funded by capital contribution.	Very basic installation. No LV link boxes.
Otorohanga CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Te Kuiti CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Taumarunui CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Turangi town	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Taupo lake edge settlements	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions. Iwi sensitive area.	Basic installation with few LV tie points and little capacity to back-feed.
Whakamaru and Mangakino villages	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions. Iwi sensitive area.	Basic installation with few LV tie points and little capacity to back-feed.

TABLE 3.34: JUSTIFICATION FOR LOW VOLTAGE UNDERGROUND NETWORK

3.3.14 Justification for SCADA Equipment

TLC has an extensive SCADA network made up of equipment that is focused on meeting quality of supply and reliability criteria. That is, its main functions are to transmit alarms, open and close breakers, give feeder loadings, remove and apply auto reclosers and give very basic flagging information when a circuit breaker trips. The communication system behind the SCADA system is relatively low cost analogue with some use of voice channels. The system is based on the Lester Abbey Powerlink product.

Systems that are much more expensive have been observed in some network companies. TLC Engineering and Asset Management staff are unaware how the system could be set up at a lower cost and give the level of reliability that the system provides.

The SCADA system is essential for controlling the network and monitoring the injection of larger distributed generators. In the 1970s and 1980s, network companies were well staffed. Since this time, industry reform has been on-going and staff numbers have been hugely reduced. SCADA has been partly responsible for the improvements in reliability, by increased automation, through this period of change.

SCADA systems also reduce cost. The TLC system carries out approximately 4000 operations p.a. If, on average, each of these operations required a site visit costing $200, then staffing savings of about $800,000 p.a. are being achieved. Once investment and maintenance costs are subtracted, it is estimated the SCADA system produces savings over and above reliability improvements of about $600,000 p.a.

3.3.15 Justification for Load Control Equipment

Load control is a way to improve asset utilisation and reduce load when the network is under stress. How these benefits are best packaged to customers and integrated into the various charging mechanisms is an issue facing the industry especially as more advanced metering develops.

The way load control systems work technically and the propagation of signals through the network is complex. A power system is designed for 50 Hz and when higher frequencies are injected various combinations of lines, cables, transformers and capacitors amplify, or reduce, the level of signal.

The TLC load control system is very basic. The controller is integrated with the SCADA system and uses the same hardware and communication systems.

The northern system is old and uses 725 Hz as the carrier frequency. (Note: A new 317 Hz system has been commissioned, but as the advanced meter/relay rollout will take 5 to 6 years to complete, the old system has to be kept in service for this period). The 725 Hz relays and injection plant are old wide band equipment and there are areas of the network that have marginal to non-operational signal levels.

The southern system has modern solid-state transmitters and receivers operating at 317 Hz. Inputs are received from the GXP, supply points, and larger distributed generators. These are summed in the system load and signals are sent out to control to fixed values of demand at GXPs, generation busbars, zone substations and feeders.

Larger distributed generators receive a rebate for the level of transmission demand their generation enables TLC to avoid.

The load control and SCADA master station is used to record and store system loadings. Time controls are used for tariff signals and daylight sensors are used to drive signals for street lighting. The introduction of the new system, the demand-based charges and an increased rollout of advanced metering does mean there is an incentive for TLC to set up a slightly better channel control structure. This is discussed in more detail in the service levels section. Looking forward TLC needs to control loadings to feeder levels.

It is hard to envisage how a lower cost system that provides reliable control could be implemented. Various options were researched as part of the evaluation of the renewal of the northern system. Power system carriers based on decabit codes with injection at 33 kV were found to be the most effective for present and foreseeable future needs. This included integration with advanced metering systems.

3.3.16 Optimisation

The current TLC disclosed valuation report under Section 16 Schedule of Optimisation and Details of the Valuation Impact on Each Optimisation reads "After working through the detailed optimisation examination in Appendix B of the handbook as per the description in Section 9, there were no network optimisations that can be justified."

Section 4

4. Service Levels

TLC provides billed connections to about 23,300 electrical installations in the greater King Country. Its business is to provide a service to customers' expectations that produces income to fund the maintenance, renewal and development of this infrastructure in a sustainable and hazard controlled way. To ensure that it is providing a service in line with customers' expectations, TLC has consulted with customers through surveys, customer clinics focus groups and other consultation meetings. TLC also consults with stakeholders and researches other industry performance.

A key objective of asset management planning is to match the level of service provided by the assets to the expectations of customers and other stakeholders. This is consistent with TLC's vision, corporate organisational objectives and goals as outlined in Section 2 of this Plan.

TLC carries out regular reviews of actual performance against targets, and of customers' feedback/expectations. The targets and expectations are also considered in day to day operational decision making.

The key performance targets are:

- Consumer oriented performance targets.
- Asset performance targets.
- Asset efficiency targets.
- Asset effectiveness targets.
- Line business efficiency targets.

The service performance targets in this section are used to:

- Inform customers of the proposed levels of service.
- Focus asset management strategies to an appropriate level of service.
- Enable customers and stakeholders to understand the suitability and affordability of the service offered.
- Over time, they will provide a measure of the effectiveness of the actions taken in accordance with the AMP.

4.1 Customer Oriented Performance Targets

The industry targets such as SAIDI minutes and SAIFI frequency are hard for customers to understand and create averaging effects that do not give enough detail about asset performance in various sectors of the network. TLC also saw the need for a modular asset management system where there is correlation between assets, service levels and charges. To meet this, a system was created where assets are grouped and these groups are then aggregated up into service level areas and charging regions. These asset blocks are called asset groups and are sized so that they can be used to manage renewal and maintenance etc. As an example a typical 11kV feeder is broken into 10 asset groups.

All costs, reliability, valuations etc. are attached to asset groups in the asset management system. These asset groups all have attached service level performance targets and measuring criteria.

The service level areas are as follows:

- Urban service level A
- Rural service levels B, C and D
- Remote rural service levels E and F

Figure 4.1 illustrates the service level areas in geographical layout.

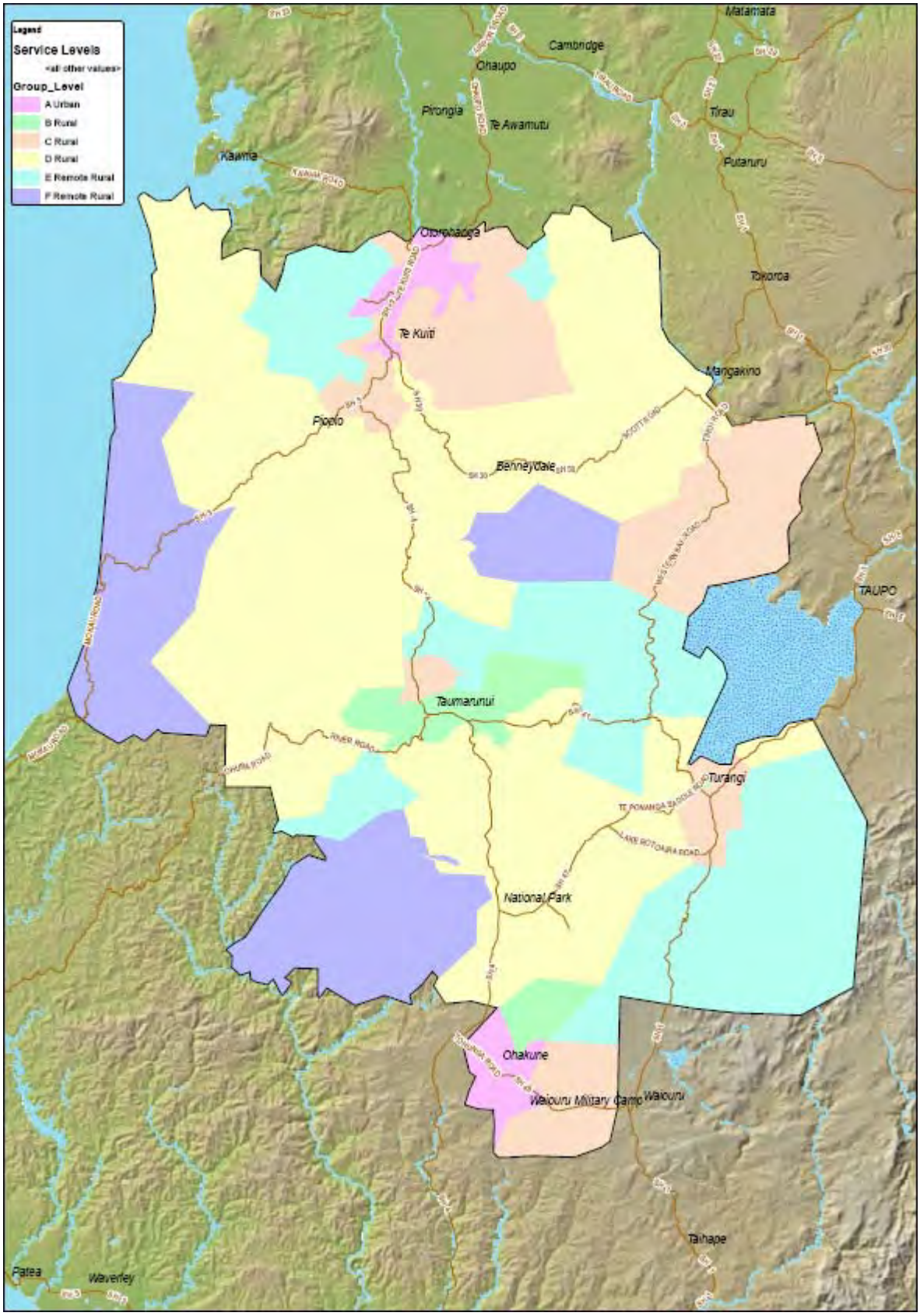


FIGURE 4.1 : SERVICE LEVEL AREAS

Two charging density categories and six regional pricing zones sit above the service level areas to complete the feedback loop between service, costs and prices.

Criteria used to determine the service level areas include:

- Customers' remoteness from supply points and depots.
- Terrain and weather effects e.g. snow in southern areas.
- The number of back feed options available.
- Customer/stakeholders expectations.
- Past asset performance.
- Expected future performance given the strategies included in this Plan.

The customer service level targets were discussed and approved by customers at focus group meetings by stakeholders and other interested parties. They were originally set in 2003 and were reviewed in 2008. The customer service level targets form part of the Terms and Conditions of Supply.

A customer survey conducted in 2009 revealed 92% of customers were satisfied with the reliability of their power supply. However there was some slippage in satisfaction with reliability since the last measurements in 2005. Specifically, there was a drop in the proportion of customers who stated they were 'extremely' or 'very satisfied' and an increase in the number of customers who stated they were 'quite satisfied' with respect to SAIDI and SAIFI. This trend is believed to be due to an increase in customer expectations, i.e. as reliability increases, customers' expectations become greater.

Note: All customer orientated service related performance targets apply to TLC network assets. The effects of other asset owners' equipment, i.e. the effects of privately owned lines, are not included.

4.1.1 Customer Oriented Performance Targets: Asset Related

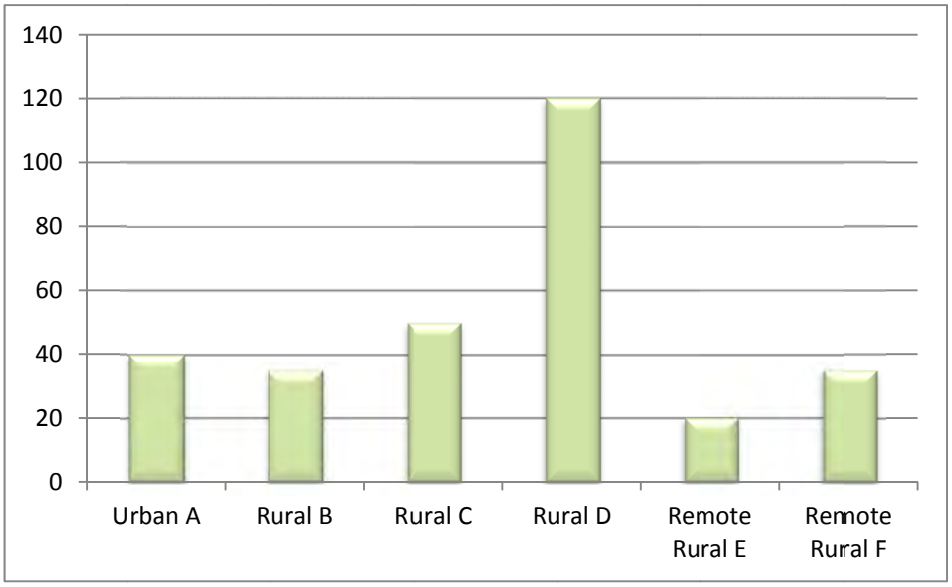
The following customer oriented performance targets (asset related) are used:

- SAIDI and SAIFI broken down by the 6 service level regions.
- Time to restore supply after an unplanned outage by the 6 service level regions.
- Maximum number of planned shutdowns per year by the 6 service level regions.
- Maximum number of long and short faults per year by the 6 service level regions.

TLC uses the BASIX computer programme to produce reports of the above performance indicators at asset group, service level and other higher reporting levels. The asset group and service level region performance is discussed in the performance section of the AMP (Section 8). These targets are consistent with business strategies and asset management objectives to operate a network that meets customer quality and reliability expectations.

4.1.1.1 SAIDI Targets

Table 4.1 lists the service level and overall SAIDI targets.



SAIDI Target	**40**	**35**	**50**	**120**	**20**	**35**	**TOTAL 300**

TABLE 4.1 : SAIDI TARGETS BY SERVICE LEVEL

At the time of this review it is proposed the SAIDI target will remain the same till financial year 2025/26. The total SAIDI target of 300 minutes has been determined as part of the customer consultation process. The split between planned and unplanned historically has been 97 and 203 minutes respectively. The 300 minute target is lower than the Commerce Commission Decision 685 SAIDI limit (307.69) as calculated by the formulae in the determination document. The breakdown of SAIDI by service level has been determined by data collected in financial year 2009/2010.

Compliance with the Commerce Commission has the potential to increase the cost of TLC's renewal programmes because of the need to use live line work methods and generator by-passes to comply with threshold targets. Work to date has shown that breaches will potentially occur from time to time. This will mainly be caused by repeated days of windy weather that do not quite trigger the normalisation calculation of the Decision 685 formulae. The repeated periods will inflate the result, and cause pressure on renewal outages, i.e. there will be an incentive to minimise renewal outages to reduce the risk of breaching the targets. If the weather patterns are severe in a particular year and the figures are tracking high, then the only method of control is either to constrain renewal and maintenance outages or require work to be done using live line techniques, which will increase costs. Neither outcome is ideal.

Customers are indicating they do not want to fund increased costs for planned renewals using live line work methods. Analysis of data has shown that about 25 SAIDI minutes would be added if additional work was completed using lower cost and de-energised methods. Looking forward it is expected that unplanned outage minutes will decrease (as a result of renewal and reliability programmes) and that this will be offset by increased renewal. As a consequence of this, and historical moving averages, the planned and unplanned split targets have been amended to 90 and 210 minutes respectively.

Table 4.2 lists the justification for SAIDI targets based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR SAIDI TARGETS	
Target and Item	**Justification**
SAIDI Consumer Considerations	Customers have said they are happy with the present level of reliability. As reliability improves customers' expectations change. Customers are now expecting reliability to be maintained or improved although they do not want to pay extra for live line work while renewal is taking place.
SAIDI Statutory Considerations	The heavy renewal programme means that outages will be required or live line techniques will be required to complete the work. Live line work is expensive and often not practical in the King Country. This will result in the need for outages. (Note: Commerce Commission Decision 685 may influence this.) SAIDI is an industry recognised measuring index.
SAIDI Regulatory Considerations	The Electricity (Safety) Regulations 2010 which came into effect on April 1st 2010 provided for the implementation of the Safety Management System, which has subsequently been incorporated into TLC's Distribution Standards. This is designed to prevent serious harm to any member of the public or significant damage to property. These Regulations also provide for the control of worker hazards. Outages are required to achieve this. Protection must be set up to operate/disconnect supply when faults occur. Supply must be turned off to allow renewal. Equipment must be renewed to eliminate/minimise hazards.
SAIDI Stakeholder Considerations	The Trusts have provided feedback requesting that reliability be maintained at present levels. This has also been confirmed by focus group members. Feedback has revealed that customers are not prepared to pay for improved reliability. Recent customer surveys have indicated that customers have an escalating reliability expectation.
SAIDI Other Considerations	The TLC area is remote and rugged in nature. Customers are often long distances from depots via roads that quickly become impassable in bad weather. Distribution Lines travel in direct routes and do not follow roads. Helicopters are often used for fault patrols and repairs. These machines cannot operate in darkness or bad weather. The TLC network has no major population centre to alter the averaging process between urban and rural customers. As a consequence of all these factors, TLC's reliability indices will always be high by industry standards. TLC has researched international papers to identify benchmarks as to the levels of reliability considered acceptable to rural customers. This work concluded that a level of 300 minutes would be considered acceptable in rural areas such as parts of Australia. (TLC customers have also confirmed these values). SAIDI targets have not been reduced over the planning period due to customer wishes to not pay additional margins for live line work. Work has been completed analysing data to Decision 685 criteria for the period 2004/05 to 2009/10. The results of this work were 307.69 SAIDI minutes as the threshold thus confirming that a 300 SAIDI minute target is realistic given the need for increased renewal work.

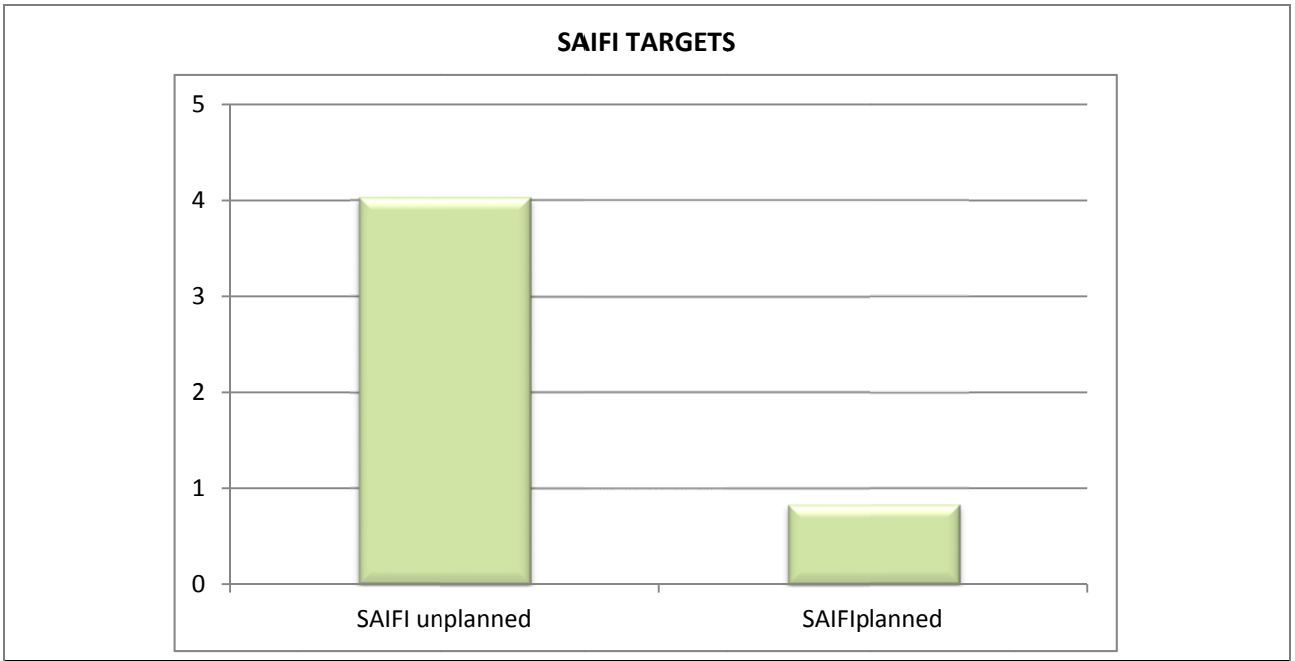
TABLE 4.2 : JUSTIFICATION FOR SAIDI TARGET LEVELS

4.1.1.2 SAIFI Targets

At the time of this review it is proposed the SAIFI target will remain at 4.86 till financial year 2025/26. The total SAIFI target (frequency) of 4.86 has been determined as part of the customer consultation process and the need to minimise the cost of renewals by carrying out a proportion of the work de-energised. The split between planned and unplanned SAIFI is 4.03 and 0.83 respectively. As with SAIDI, this target will likely be greater than that determined by the Commerce Commission Decision 685 threshold calculations (4.15) during periods over the planning period. This is due to the fact that Decision 685 threshold is a normalised figure and the SAIFI target is not. Compliance with the determination will add additional cost to TLC's renewal programmes for live line work and generator by-passes.

Due to technical difficulties the SAIFI target has not been broken down to service level. At the time of the review, the Basix database was able to report on total SAIFI; however, it had not been configured to accurately report on SAIFI at service levels.

Table 4.3 lists the unplanned and planned SAIFI targets.



SAIFI Target	**4.03**	**0.83**	**TOTAL 4.86**

TABLE 4.3 TARGETS FOR PLANNED AND UNPLANNED SAIFI

Both SAIFI and SAIDI will be sensitive to threshold compliance due to the nature of the TLC network. SAIFI will be driven up at a greater rate as opposed to SAIDI during periods when extensive use of generator by-pass for planned outages is used and extensive switching occurs during unplanned events.

Table 4.4 lists the justification for SAIFI targets based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR SAIFI TARGETS	
Target and Item	**Justification**
SAIFI Consumer Considerations	Switching surges, and the frequency of outages, often upset customers' electronic equipment. As per SAIDI, customers want the present numbers of outages maintained or improved. However they do not want to pay extra for live line work while renewal is taking place.
SAIFI Statutory Considerations	As per SAIDI, live line work is difficult, costly and often not practical in the King Country. Generators energising lines beyond work sites can be used to reduce SAIDI but may increase SAIFI. Outages have to occur at the end of shutdowns because of synchronising difficulties. A reduced target will be difficult to achieve.
SAIFI Regulatory Considerations	As per SAIDI. Regulatory requirements driven by renewals, electricity governance rules (AUFLS relays) and the like will put pressure on SAIFI performance.
SAIFI Stakeholder Considerations	As per SAIDI and customer considerations.
SAIFI Other Considerations	SAIFI figures are expected to remain high by industry standards due to the nature of the network. TLC has researched international papers to identify international benchmarks as to the levels of reliability considered acceptable to rural customers. This research concluded that an average SAIFI level of 3.91 would be considered acceptable in places such as rural Australia. TLC customers have concurred with this assessment. Due to the heavy renewal programme and the decision taken by Directors not to increase budgets for live line work, the SAIFI frequency target has been incremented by the amount that the heavy renewal programme is expected to cause. Work has been completed analysing data to Decision 685 for the period 2004/05 to 2010/11 (YTD). The results of this work confirm the need for an average 4.86 frequency target given the requirement for increased renewal work.

TABLE 4.4: JUSTIFICATION FOR SAIFI TARGETS

4.1.1.3 Time to Restore Supply

The customer agreed performance times to restore supply after an unplanned outage are listed in Table 4.5 by service level. Achieving these targets is not always possible because of the practical realities of getting the required staff and equipment to site to carry out repairs.

TLC sets targets to measure how often this agreed customer performance is achieved. The targets are set according to 2009/2010 performance. The reason for using the 2009/2010 performance is that TLC only has one year of data available at service levels. This is due to technical difficulties when transferring data from TLC's old database (before 2009 /2010) into the Basix database. The other factor in determining the targets is the time customers will accept for unplanned outages. The measuring index of this target is based on the percentage of events that do not exceed this target. Table 4.5 lists these target figures.

TARGETS: MAXIMUM TIME TO RESTORE SUPPLY						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum time to restore supply after an unplanned outage (hours)	3	6	6	6	12	12
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%

TABLE 4.5 TARGETS FOR MAXIMUM TIME TO RESTORE SUPPLY BY SERVICE LEVEL AND THE PERCENTAGE OF EVENTS TO ACHIEVE THE TARGET

Table 4.6 lists the justification for target levels of service related to time taken to restore supply based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR MAXIMUM TIME TO RESTORE SUPPLY TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that outages happen from time to time. The maximum time customers will accept for unplanned outages for urban areas is 3 hours, 6 hours for rural areas and 12 hours for remote rural areas. 3 hours has been found to be the upper threshold of urban life styles. 6 hours in rural areas equates to the time between daily milking. 12 hours in remote rural areas equates to the typical timeframe stock water systems become empty, stock determine electric fences are no longer energised and freezers begin to thaw.
Statutory Considerations	There is no Statutory requirement to restore power to areas by set times other than cumulative Commerce Commission thresholds. If it takes longer to restore supply customers often voice frustration by complaints to regulators and other stakeholders.
Regulatory Requirements	There is no Regulatory requirement to restore power to areas by set times. It is often necessary to extend outage times to control hazards.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders. This has a direct effect on the economic and social well-being of the region.
Other Considerations	Experience shows that typical maximum time taken to restore supplies is 3 hours for urban areas, 6 hours for rural areas and 12 hours for remote rural areas. There are exceptions and the risk of these times being exceeded is 15% for Urban A and Rural D, 11% for Rural B, 13% for Rural C and Remote Rural F, and 12% for Remote Rural E as detailed in the terms and conditions of supply.

TABLE 4.6: JUSTIFICATION FOR MAXIMUM TIME TO RESTORE SUPPLY TARGETS

4.1.1.4 Maximum Number of Planned Shutdowns per Year by Service Level

The customer agreed maximum numbers of planned shutdowns by the service level are listed in Table 4.7. Achieving this in all cases is not possible because of an extensive renewal programme and a large number of aged hazardous assets. Shutdowns are necessary to complete this work, especially when old hazardous assets are involved.

As a consequence, TLC sets targets to measure how often this agreed customer performance is achieved. The targets are set according to 2009/2010 performance. The reason for using the 2009/2010 performance is that TLC only has one year of data available at service levels, due to technical difficulties when transferring data from TLC's old database (before 2009 /2010) into the Basix database. The measuring index of this is based on the percentage of events that complied with this target. Table 4.7 lists these amounts.

TARGETS: MAXIMUM NUMBER OF PLANNED SHUTDOWNS						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum number of planned shutdowns per year	2	4	6	6	8	10
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%

TABLE 4.7 TARGETS FOR MAXIMUM PLANNED SHUTDOWNS PER YEAR BY SERVICE LEVEL AND THE PERCENTAGE OF EVENTS TO ACHIEVE THE TARGET

Table 4.8 summarises the justifications for target levels of service related to the maximum number of planned shutdowns per year by service level.

JUSTIFICATION FOR MAXIMUM PLANNED SHUTDOWN TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that planned shutdowns are necessary; although they do not like repeated outages. Based on feedback from customer focus groups, commercial customers and complaints, the maximum number of planned outages that customers have found to be acceptable are 2 for Urban A, 4 for Rural B, 6 for Rural C and D, 8 for Remote Rural E and 10 for Remote Rural F.
Statutory Considerations	There is no Statutory requirement for a set number of outages. The use of live line techniques on the TLC network is difficult, expensive and often not practical in the King Country. The Commerce Commission has set new reliability thresholds. Balancing low cost de-energised renewal work with more expensive live line techniques or use of generator by-pass methods is an on-going topic of discussion between the regulators, TLC and its customers.
Regulatory Considerations	Outages are often necessary for hazard control, renewal, grid emergencies and other requirements under the electricity and HSE regulations.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders as this has a direct effect on the economic and social well-being of the region.
Other Considerations	The targets are a balance between customers' expectations and the practical issues associated with an extensive renewal programme. The targets do force contractors and network operators to carefully plan work and maximise the work done during any one outage. They have been set to allow renewal work to be substantially completed without the use of more expensive live line techniques and generator by pass techniques. The number of outages increases as the remoteness increases due to a reduced number of back feeds being available.

TABLE 4.8: JUSTIFICATION FOR MAXIMUM NUMBER OF PLANNED SHUTDOWN TARGETS

4.1.1.5 Maximum Number of Unplanned Shutdowns per Year by Service Level

The customer agreed maximum numbers of unplanned shutdowns (short and long faults) by service level are listed in Table 4.9. Achieving this in all cases is not possible because of the number of aged hazardous assets in the TLC network, the rugged environment of King Country and extreme events.

TLC sets targets to measure how often this agreed customer performance is achieved. The measuring index of this is based on the percentage of events that complied with the target. Table 4.9 lists these target figures.

TARGETS: MAXIMUM NUMBER OF UNPLANNED SHUTDOWNS						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum number of long unplanned shutdowns per year (Greater than 1 minute)	5	15	15	15	25	25
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%
Maximum number of short unplanned shutdowns per year (Less than 1 minute)	20	20	60	60	60	160
Target % of events that achieve this agreed performance	98%	98%	98%	98%	98%	98%

TABLE 4.9 MAXIMUM NUMBER OF SHORT AND LONG FAULTS PER YEAR BY SERVICE LEVEL AND THE TARGETED LEVEL OF EVENTS WHERE THIS IS NOT EXCEEDED

Table 4.10 summarises the justifications for target levels of service related to the maximum number of unplanned shutdowns per year by service level.

JUSTIFICATION FOR MAXIMUM UNPLANNED SHUTDOWN TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that faults occur but do not enjoy the inconvenience when they do occur. As a consequence TLC has set numerical limits as outlined in Table 4.10. These limits are set after analysing historic data and feedback from customers. TLC uses auto reclose schemes extensively throughout the network as a tool to reduce SAIDI times. The use of auto reclose schemes does mean customers see short faults. Auto recloses give warnings of potential problems on the network, these are then analysed by the engineering department. Switching and other surges on the network often destroy customers' electronic equipment. Measuring and setting targets that drive the design and operation of the network to eliminate these effects are important customer service considerations.
Statutory Considerations	There is no Statutory requirement at this time for the number of unplanned short and long duration faults. It is suspected that short duration faults (recloses) may require disclosure in the future.
Regulatory Considerations	There are no Regulatory considerations for the number of unplanned short and long faults. Protective devices must isolate faulty equipment in compliance with the electricity regulations.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders as this has a direct effect on the economic and social well-being of the region.
Other Considerations	The targets are a balance between existing network performance, customers' expectations and the costs associated with improving network performance. Alternative supplies are often not practical and not cost justifiable for rural ICPs. As a consequence, rural customers see more unplanned events.

TABLE 4.10: JUSTIFICATION FOR MAXIMUM NUMBER OF UNPLANNED SHUTDOWN TARGETS

4.1.2 Customer Oriented Performance Targets – Service Related

The following customer oriented service related targets are used:

- Telephone calls coming into the organisation. TLC is decoupled from retailers and receives all telephone calls locally.
- Unanswered telephone calls coming into the organisation.
- Unresolved complaints to the Electricity and Gas Industry Complaints Commission's complaints resolution processes.
- Number of focus group meetings - TLC has set up several regional focus groups who meet with senior management on a regular basis to discuss service and other outstanding issues.
- Number of customer clinics - TLC schedules meetings in regions where customers come and discuss collectively, or individually, their service concerns.

4.1.2.1 Telephone Calls Coming into the Organisation

The number of telephone calls TLC receives is a measure of the service delivered by the organisation. Experience has shown that customers call when there is a service problem such as incorrect accounts, misadvised planned outages or to report unplanned outages. The target is not to exceed 4500 telephone calls received per month. Incoming calls are recorded by the telephone system and monthly reports detail call statistics.

Table 4.11 summarises the justifications for target levels of service related to the maximum number of calls coming into the organisation on a monthly basis.

JUSTIFICATION FOR TELEPHONE CALLS COMING INTO THE ORGANISATION TARGETS	
Item	**Justification**
Consumer Considerations	Large numbers of customers call when accounts are incorrect, planned outages are incorrectly advertised or when unplanned outages occur. Monitoring call numbers gives an indication of customer issues. The indices can be easily measured and the target has been set based on the numbers of incoming calls that are received during periods when there are no exceptional events. The call numbers double, treble or quadruple when a bill ing run has errors or there is a major outage event.
Statutory Considerations	There is no Statutory requirement regarding the number of calls from customers. Customers calling and being able to talk to someone who can solve their problem or address their need is very important. Complaints to various bodies (EGCC, EC, COMCOM, MED, MPs) have occurred when legacy telephone systems and resources were not adequate to answer billing enquiries or loss of supply calls.
Regulatory Considerations	There is no Regulatory requirement for the number of calls from customers. There is a requirement for TLC to receive information from customers and other stakeholders on hazards and to respond to these hazards in a timely manner.
Stakeholder Considerations	TLC shareholding stakeholders have responded to customers' concerns about out of area telephone call centres. TLC has been instructed to have resources in place to answer calls at a local level using people who have local knowledge of the area. Timely answering of calls and the numbers of calls is important to shareholding stakeholders.
Other Considerations	To improve our customer service, TLC needs to stay in contact with customers, encourage customers to call and needs to be approachable. For quality purposes TLC monitor the number of calls received on a monthly basis.

TABLE 4.11: JUSTIFICATION FOR TARGET LEVELS OF CALLS COMING INTO THE ORGANISATION

4.1.2.2 Unanswered Telephone Calls

Telephone calls that are not answered within a short period indicate problems with service. Customers do not appreciate unanswered calls. The unanswered telephone calls target is not to exceed 3% of telephone calls coming into the organisation per month. Unanswered incoming calls are monitored by the telephone system and the reports are reviewed on a regular basis. The unanswered calls target includes busy signal and short duration calls.

Table 4.12 summarises the justifications for target levels of service related to the maximum number of telephone calls that go unanswered. The target is based on present levels of service.

JUSTIFICATION FOR UNANSWERED TELEPHONE CALL TARGETS	
Item	**Justification**
Consumer Considerations	Unanswered calls indicate a peak customer service issue or not enough resources to answer calls. Customers do not appreciate the lack of response. The target level of 3% per month is based on historic records and performance. From a customer perspective the number of unanswered calls should be as low as possible. Balancing resources can be difficult for short duration peak times.
Statutory Considerations	There is no Statutory requirement for TLC to have a certain level of unanswered calls. Customers do not appreciate unanswered calls. Complaints to various bodies (EGCC, COMCOM, MED, MPs) have occurred when calls go unanswered and customers cannot get issues resolved.
Regulatory Considerations	There is no Regulatory requirement for TLC to have a certain level of unanswered calls. There is a requirement for TLC to answer calls from stakeholders and customers and respond to these, especially when they are associated with an emergency event.
Stakeholder Considerations	TLC shareholding stakeholders have instructed TLC to have resources in place to answer calls at a local level using people who have local knowledge of the area. They accept that it is not economic to employ a large number of resources to answer every call. Monitoring the level of unanswered calls is considered an important target and measurement by stakeholders.
Other Considerations	Call levels are not consistent, there are peaks and troughs. The causes of these are often unforeseeable and in fault situations, for example, some calls may go unanswered. Minimising and controlling this at a level acceptable to customers and stakeholders is important. Customers have to accept that having resources to answer telephone calls adds cost. The 3% target level has resulted in a much lower level of complaints as compared to the use of remote answering centres. The objective looking forward is to improve the service and hold costs. These objectives will most likely be achieved through the application of better telephone technology.

TABLE 4.12: JUSTIFICATION FOR TARGET LEVELS OF UNANSWERED TELEPHONE CALLS

4.1.2.3 Unresolved Complaints Annually Investigated by the Electricity and Gas Industry Complaints Commission or Alternative Complaints Resolution Organisation

Unanswered queries cause frustration and extra costs (staff time and EGCC charges). This can result in dissatisfied customers who may lodge a complaint with the Electricity and Gas Industry Complaints Commission. TLC have set a target to not exceed a total of six complaints per annum that take longer than 3 months for TLC and the Commission to investigate and resolve. The target is measured by recording the numbers of complaints that go to the EGCC and the relevant date. The target has been set based on what is considered a realistic level given TLC's situation.

Table 4.13 summarises the justifications for target levels of service related to the unresolved complaints annually investigated by the EGC or alternate complaints organisation.

JUSTICATION FOR UNRESOLVED COMPLAINT TARGETS	
Item	**Justification**
Consumer Considerations	Due to TLC's unique demand and direct billing scheme, a number of customers believe that their line charges are excessive. They have difficulty understanding independent line and energy charges compared with retailers' repackaged charges in other parts of the country. The complaints made to the EGCC have to be funded by charges to TLC. These costs go into the overhead operating charges, which in turn have to be funded by other customers. As a consequence of this, TLC is incentivised to minimise complaints that go to this detailed investigation stage. Most customers understand the issues when they have them explained; however, a number do not and continue with the complaint. This costs TLC in staff time and EGCC charges. A target has therefore been set to limit these complaints to a total of six per annum that take longer than 3 months for TLC and the Commission to investigate and resolve. This level is measurable and has been set based on historical information.
Statutory Considerations	There is no Statutory requirement to have a set target of number of complaints to the EGCC. However EGCC costs have to be funded and this displaces other operating costs. This creates indirect Statutory pressure to minimise complaints costs.
Regulatory Considerations	There is no Regulatory requirement to have a set number of complaints to the EGCC. There is a Regulatory requirement to be part of a complaints resolution process.
Stakeholder Considerations	Complaints to the EGCC cost TLC, and other customers, money and results in customer dissatisfaction. Stakeholders require the numbers of customers involved in this process to be minimised.
Other Considerations	The target is easy to measure and gives a further indication of TLC's customer service performance. The better the customer service, the smaller the number of frustrated customers.

TABLE 4.13: JUSTIFICATIONS FOR TARGETS RELATED TO UNRESOLVED COMPLAINTS INVESTIGATED BY EGCC OR ALTERNATE COMPLAINTS ORGANISATION

4.1.2.4 Focus Group Meetings

Focus groups are groups of customers who meet with senior management to discuss the organisation's performance and other issues. Customers bring their local and other issues forward at these meetings. Management usually prepare and present a summary of key current issues at these meetings.

The most recent presentations have focused on price, quality and capacity trade-offs for the Ohakune area. Other recent presentations have centred on the need to complete renewal programmes and to obtain funding for these from revenue. Focus groups normally include various customers and other interested stakeholders from the area. The size of the group varies from 10 customers to over 80. A Committee was established at the request of a local MP. At these meetings discussion is generally around the direct line charging issues that customers have.

Initially the concern of customers attending these meetings was around network reliability but, as this has improved, the focus has moved to charges and capacity. The target is to hold at least 5 meetings per year. This target is measured by logging the meetings in a database. The target has been set based on the number of meetings that TLC can realistically handle given its present staffing levels.

Table 4.14 summarises the justifications for target levels of service related to focus group meetings.

JUSTIFICATION FOR FOCUS GROUP MEETING TARGETS	
Item	**Justification**
Consumer Considerations	The number of annual meetings is regulated by the available time of customers and senior management. Most focus groups presently are requesting an annual meeting. A number of focus groups have been meeting frequently to resolve and keep updated on specific issues such as recent Commerce Commission publications and pricing levels. Focus groups are a mechanism for discussing price quality trade-offs, the AMP, Corporate objectives, pricing and service. Often an independent chairman is used to run the meetings.
Statutory Considerations	There was a Statutory requirement for engagement with customers to discuss price/quality trade-offs. In the current Plan period TLC's prices and quality are set by a Default Price Path. TLC will have to likely apply for a CPP (Customised Price Path) and as part of this will have to demonstrate customer engagement on various issues. The focus group meetings will be a vehicle to achieve this.
Regulatory Considerations	As per above. Focus group meetings have also included discussions on hazard control, related high voltage lines issues and supply quality.
Stakeholder Considerations	Stakeholders require senior management to engage with customers. Focus groups are an essential link in this chain.
Other Considerations	Focus group meetings are very satisfying, particularly when customers endorse and appreciate the hard work staff put into maintaining supply to customers in a rugged difficult environment.

TABLE 4.14: JUSTIFICATION FOR TARGET LEVEL OF FOCUS GROUP MEETINGS

4.1.2.5 Customer Clinics

Customer clinics are meetings that occur between customer services staff and customers throughout the area. They are intended to provide a TLC point of contact for customers that are geographically removed from TLC's main office. Advertisements are placed in local papers and appointments arranged. Discussions can be collective or individual depending on the issues. Most of the customers' requests are centred round billing issues. Any requests relating to assets are passed onto asset management and engineering staff.

The target is to have 12 customer clinics offered annually. This target is measured by logging the clinics into a database and has been set on the number of meetings that TLC can realistically handle given its present staffing levels.

Table 4.15 summarises the justification for target levels of service related to number of customer clinics.

JUSTIFICATION FOR CUSTOMER CLINIC TARGETS	
Item	**Justification**
Consumer Considerations	Customers appreciate meetings in local areas with staff to discuss specific issues. The target has been set based on present resources and the numbers of customers who use the services.
Statutory Considerations	Commerce Commission will require customer consultation (for CPP applications). Customer clinics are one of the tools TLC uses to achieve this.
Regulatory Considerations	Customer clinics do from time to time involve the discussion of hazard control and power quality issues.
Stakeholder Considerations	Stakeholders request that TLC establishes and maintains direct relationships with its customers. A MP, whose electorate did cover part of the TLC network area, requested that a group be set up to discuss and try to resolve a number of the complaints that have come from customers in the Taumarunui area.
Other Considerations	Another important link in the interaction with customers. A target has been set to ensure the task is given priority.

TABLE 4.15: JUSTIFICATION FOR TARGET LEVEL OF CUSTOMER CLINICS

4.2 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and the Efficiency of Line Business Activity

4.2.1 Asset performance targets

The following targets are used to measure asset performance:

- Power Quality: -
  - » Voltage complaints.
  - » Legacy Voltage Issues.
  - » Voltage Surge Complaints.
  - » Harmonics levels in various key locations.
- System component performance.
- Environment performance.

These targets are consistent with business strategies and asset management objectives to operate a network that meets customer quality and reliability expectations. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

4.2.1.1 Power Quality

TLC's Power quality objectives are to match the performance of assets with statutory requirements and the performance customers expect and are willing to pay for. Quality targets reflect industry accepted levels of voltage and harmonic distortion. TLC uses legislation, customer complaints, code of practice, historical experience and network studies to determine what is acceptable or tolerable.

4.2.1.1.1 Voltage Complaints

TLC receives voltage complaints as a consequence of network asset and customers' works/installations performance. There are many causes of voltage being outside limits. Some of the causes can quickly be eliminated by adjusting regulators or transformer taps. Other problems require either network or customer works/installation upgrades. Often customers choose not to fund works/installation upgrades and instead choose to tolerate inadequate supply. These customers are excluded from the performance target. TLC has been investing in equipment that improves network voltage regulation and can predict network performance. The annual target level for voltage complaints is not more than 10 per year of proven long term complaints throughout the planning period. Complaint measurement does not include short term events, faults, customer works/installation problems, Transpower system events and similar events beyond TLC's control. The level was set based on the number of historic complaints.

4.2.1.1.2 Voltage Studies: Legacy Issues

Improved network analysis has identified a number of parts of the 11 kV network that have operated outside of Regulatory limits for many years. These have been caused mostly by cumulative load growth and legacy issues. TLC has a number of legacy voltage constraints that have been identified and these determine the levels that load control equipment is set.

TLC has included in the AMP a programme to deploy more regulators and other voltage improvement tools, the programme has been levelled and prioritised based on the extent of each violation. The purpose of the programme is to bring the operating voltage back within Regulatory limits [ESR 28] at all sites within the planning period. Details of the programme can be found in Section 5 of the Plan. The target has been set based on the number of additional regulators in the annual plan.

4.2.1.1.3 Voltage Surge Complaints

Voltage surges can destroy appliances which cause inconvenience, nuisance and cost to customers. TLC has implemented a system of measuring the complaints and the related letters it has to send to customers when they claim this damage against their insurance policies. TLC has set a performance target to benchmark and measure these complaints. TLC has set a target to not exceed 80 voltage surge complaints per year. The number has been set based on the typical number of historical complaints.

4.2.1.1.4 Harmonic Levels in Various Key Locations

Harmonics are the by-products of modern electronics. They occur frequently when there are large numbers of personal computers (single phase loads), uninterruptible power supplies (UPSs), variable frequency drives (AC and DC) or any electronic device using solid state power switching supplies to convert incoming AC to DC. As a result of these, harmonics can cause a multitude of problems from increasing in current to interference in the system.

TLC measures harmonic distortion via modern regulator equipment and annual spot checks at key points of the network. TLC closely monitors harmonic distortion, with maximum targets of 10% for 3-wire systems and 30% for SWER systems. TLC is concerned about harmonic levels due to amplification characteristics caused by lightly loaded rural lines and SWER systems.

As a consequence, TLC has set a quality performance objective to monitor these key sites and investigate further on the increase of harmonic distortion. This may lead to changes in future connection standards and terms and conditions of supply. The target is to have no sites exceeding the above limits on annual spot measurements throughout the planning period. This target has been set based around information on actual measurements taken.

Table 4.16 summarises the justification for quality asset performance targets.

JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS	
Item	**Justification of Targets**
Consumer Considerations	Voltage Complaints: The target has been set based on historic complaint levels and takes into account legacy design and connection practices. Voltage Studies: Legacy Issues – Voltage quality will be outside Regulatory limits unless action is taken. Harmonic Levels: Harmonics cause a multitude of problems including interference and other problems in the power system. Voltage Surges: Voltage surges often destroy electronic components. Many of these surges are caused by events such as switching surges and lightning. When appliances are destroyed customers have to claim against their insurance policies for new ones. If they have no insurance then they have to fund these themselves. TLC's objective is to minimise the risk of appliances being destroyed by engineering to minimise surges.
Statutory Considerations	Supply quality is included in electricity requirements.
Regulatory Considerations	Voltage: Voltage levels are covered by regulations. TLC uses these voltage limits as its quality criteria. Harmonics: Harmonic level limits are currently detailed in NZECP36 - this code is somewhat dated by international standards. TLC uses this as its harmonic quality criteria. The target (10% for 3-wire systems and 30% for SWER systems THD) is a TLC performance target. The target set for further investigation (5% change in reading) is all part of TLC's strategy to understand harmonic flows and the implications of these in TLC's network, particularly with the unique multitude of SWER systems. Voltage Surges: There are no Regulatory criteria for voltage surges.
Stakeholder Considerations	Voltage: Stakeholders require voltage levels to comply with regulations. Ideally all parts of the network should comply. The reality is that there are a number of legacy issues that need addressing. Stakeholders need to understand the level of non-compliance and the steps that are in place to address these issues. Harmonic Levels: Stakeholders require network harmonic levels to comply with the regulated code of practice. They wish to be aware of strategies in place to manage this issue to ensure the network continues to be sustainable. The target gives them an assurance that this issue is being monitored. Voltage Surges: Stakeholders wish the number of destroyed appliances to be minimised.

JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS	
Item	**Justification of Targets**
Other Considerations	Voltage: Most appliances are rated at 240Volts. Regulations state a nominal voltage of 230 Volts. Customers can have problems with equipment because of this mismatch. As a consequence it is important that targets for complaints are reasonably generous. Investigation of complaints often reveals that this mismatch is causing the customers problems. Harmonics: Harmonics is a complex subject. Tests show that electronic compact light bulbs, heat pumps and soft starters produce high levels of harmonics. Hence monitoring the network levels is considered important for long term sustainability. Other Considerations: TLC wishes to manage its assets to minimise the potential of voltage surges. TLC is also encouraging customers to take demand side responsibility by giving away plug-in surge protection devices to customers.

TABLE 4.16: JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS

4.2.1.2 System Component Performance: Failures

As part of the outage reporting system TLC has monitored system component failures that have caused faults. This measurement has given an indication of the number of events occurring. These events are mostly caused by old components deteriorating to failure.

The renewal programme should reduce the number of component failures that lead to faults. The targets for the planning period are listed in Table 4.17. This is a simple measure of the impact of and the need for renewal programmes. The target has been set based on historical levels of failure and the expectation these will reduce as the renewal programmes continue.

COMPONENT FAILURE TARGETS	
Year	**Target**
2010/11	254
2011/12	244
2012/13	240
2013/14	236
2014/15	232
2015/16	228
2016/17	224
2017/18	220
2018/19	216
2019/20	212
2020/21	208
2021/22	204
2022/23	200
2023/24	196
2024/25	192
2025/26	188
2026/27	184

TABLE 4.17 COMPONENT FAILURE TARGETS

Table 4.18 summarises the justification for the system component failures performance targets.

JUSTIFICATION FOR THE SYSTEM COMPONENT FAILURES PERFORMANCE TARGETS	
Item	**Justification**
Consumer Considerations	This is a measure of the number of component failures that cause outages. For example, an insulator failure that causes an outage. Counting these items via TLC's asset group based outage reporting system gives a measure of the effectiveness of TLC's maintenance and renewal programmes. Customers are not happy when outages that affect them could have been prevented through better maintenance programmes. The target level has been set based on historically monitored system component failures that have caused faults. It may require adjusting as a consequence of better data coming out of the asset management system. The target was adjusted for the 2010/11 year period forward as compared to 2009/10 year. This was due to data from the new outage reporting system indicating that the previous data collection process was not robust and therefore the level of reporting was not totally consistent
Statutory Considerations	The target and trends with the numbers of component failures will be used in submissions to the Commerce Commission and other regulators. It will be used to highlight the effectiveness of and the need for TLC's renewal programmes.
Regulatory Considerations	In addition to causing outages, faulty equipment creates hazards for both staff and the public. This measure gives impetus to the need for maintenance and renewal programmes.
Stakeholder Considerations	Stakeholders want a sustainable network - they do not want to see increasing number of components failing due to age. This target and measure provides reassurance to stakeholders that maintenance and renewal programmes are working.
Other Considerations	TLC has been measuring these numbers for the last nine years and now has a reasonable amount of data on components that have failed and caused faults. The system component failure target will be reviewed during the planning period and some further adjustment may have to be made as data quality improves.

TABLE 4.18: JUSTIFICATION FOR ASSET PERFORMANCE TARGETS: SYSTEM COMPONENT FAILURES

4.2.1.3 Environmental Performance

The environmental performance is measured using two targets. The first target is not to be prosecuted or receive abatement notices from environment control agencies. The second target is to ensure all environmental improvement works scheduled for a particular year (as detailed in this Plan) and the supporting works programmes are completed. The targets have been based on historical performance and the works included in the Plan.

Table 4.19 lists the environmental performance targets for the planning period.

ENVIRONMENTAL PERFORMANCE TARGETS		
Year	**Prosecution or Abatement Notices**	**Environmental Impact Works Due For Completion**
2010/11	0	1
2011/12	0	1
2012/13	0	3
2013/14	0	0
2014/15	0	0
2015/16	0	1
2016/17	0	1
2017/18	0	0
2018/19	0	0
2019/20	0	0
2020/21	0	1
2021/22	0	1
2022/23	0	1
2023/24	0	0
2024/25	0	0
2025/26	0	0
2026/27	0	0
2027/28	0	0

TABLE 4.19 ENVIRONMENTAL PERFORMANCE TARGETS

Table 4.20 summarises the justification for the environmental performance targets.

JUSTIFICATION FOR THE ENVIRONMENTAL PERFORMANCE TARGETS	
Item	**Justification for Target**
Consumer Considerations	Environmental Control Agencies: No prosecutions or abatement notices. Customers are increasingly becoming aware of and concerned about organisations that breach environmental standards. Completion of Environmental Projects: TLC has a number of sites that have a level of environmental risk. The programme in the AMP includes projects to remove the risks. Customers want environmental risks associated with TLC assets minimised.
Statutory Considerations	Environmental Control Agencies: No prosecutions or abatement notices - environmental prosecutions and abatement notices should be avoided. The costs of prosecution and/or abatement notices is significant and funding these would offsets other, often more productive, operating expenditure. Completion of Environmental Projects: Environmental risk projects are generally high priority and the legislators would have difficulty should TLC to treat such projects with lower priority. Making sure they are completed is likely to be more important to the legislators.
Regulatory Considerations	Environmental Control Agencies: No prosecutions or abatement notices. From a Regulatory consideration, environmental prosecutions and abatement notices should be avoided although no specific targets are set. Completion of Environmental Projects: The reduction in environmental risk will be supported by regulators.
Stakeholder Considerations	Environmental Control Agencies: No prosecutions or abatement notices. From a stakeholder's perspective, abatement notices and prosecutions should be avoided. Completion of Environmental Projects: From a stakeholder's perspective all environmental improvement projects should be completed.
Other Considerations	Environmental Control Agencies: No prosecutions or abatement notices. Abatement notices and prosecutions need to be avoided. Completion of Environmental Projects: Environmental projects need to be completed especially given that many assets are located in sensitive areas.

TABLE 4.20: JUSTIFICATION FOR ASSET PERFORMANCE TARGETS: ENVIRONMENTAL PERFORMANCE

4.2.2 Asset Efficiency Targets

The following targets are used to measure asset efficiency:

- Network losses: Technical and non-technical.
- Network power factor.
- Load factor.

These targets are consistent with the objective to renew, develop and maintain a network that fulfils stakeholders' values and expectations. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

4.2.2.1 Network Losses: Technical and Non-Technical

Network losses have historically been calculated from the energy coming into and delivered out of the network. Loss calculations became more difficult when the industry was split in 1999 and it is only over the last year that reports from the Reconciliation Manager have become available and made it possible to calculate meaningful figures. The notion of technical and non-technical losses has also been introduced.

TLC has some control over technical losses but little influence over the retailer functions that lead to non-technical losses. Technical losses are generally I^2R and iron losses. Non-technical losses are metering errors associated with inaccurate or failed metering, meter reading errors and variations caused by the timing of meter reads.

As outlined in other sections, TLC has set up an extensive network analysis model that models right down to distribution transformer level. This model calculates technical losses and was set up as a bench mark in the 2006/07 year.

A result of the 1999 reforms was that network companies were no longer financially responsible for losses and as a consequence it became difficult to use losses in financial calculations to justify expenditure. Losses still exist and are becoming increasingly recognised as a critical long term issue. Tracking the network losses performance and how design decisions impact on these is considered important information.

Distributed generation and power flows (both active and reactive) associated with this influence losses significantly as does the location and variation of network loads. Setting a target for technical losses is not a straight forward process and the regions of the network in various states have to be considered. The technical loss factor is set based on power flow studies.

Table 4.21 lists the targets that have been set for technical losses for contiguous network regions under heavy and light loads with the generation injecting at expected levels throughout the planning period.

TECHNICAL LOSS TARGETS		
Network Region	**Heavy Load**	**Light Load**
North	7.00%	2.00%
Central	8.00%	5.00%
Ohakune	9.00%	2.00%

TABLE 4.21: TECHNICAL LOSS TARGETS BY REGION

Averaging data in Table 4.21 gives an overall technical loss expectation of about 6 to 7 %. Analysis of electricity meter registry and TLC's SCADA data shows that the ratio of billed energy to energy coming into the network is showing combined technical and non-technical loss figures that do not make sense e.g. they can vary from 12% to -3%. Given that TLC has relatively firm data for the technical losses (subject to averaging assumptions) the loss factors disclosed to the market are considered to be the most accurate figures available.

TLC has not set a non- technical loss factor target due to non-technical losses being mostly outside TLC's control. However it is monitoring the level and passing this information on to retailers. A level of concern has been expressed to retailers about the varying level of non-technical issues, including the difficulty in getting accurate information.

Table 4.22 summarises the justification for network loss targets.

JUSTIFICATION FOR NETWORK LOSS TARGETS	
Item	**Justification**
Consumer Considerations	Customers end up paying for losses through energy charges and they are often more concerned about capital related costs than the impact of system losses. Customers tend to be attracted to low cost capital solutions that produce higher losses. Customers are also concerned about long term environmental effects. The loss targets have been set based on present network performance and the objective of the targets is benchmarking. The current levels are known and movement in these targets needs to be understood by customers. The present benchmarking also has the ability to illustrate to customers their retailer's performance with meter reading, metering data and other errors coming out of their metering and billing systems.
Statutory Considerations	The Statutory controllers are indicating in their documents that network companies should be more innovative to promote energy efficiency. Lower loss networks have to be justified. Deployment of distributed generation may or may not reduce losses. Data analysis and network modelling serve to give an accurate picture of losses today so that as Statutory development moves forward TLC can work forward from a position of fact. Accurate submissions and arguments can be formulated as required.
Regulatory Considerations	There is no current Regulatory target for losses. Losses have to be disclosed. The difficulty TLC has is that technical losses can be calculated (subject to assumptions) but non-technical losses have to be sourced from retail data and the market processes. These (based on available data) have a variable level of accuracy. The targets TLC has set segregate these and going forward will clearly show the impact of technical and non-technical losses.
Stakeholder Considerations	Losses are a complex subject for most stakeholders. They are interested in knowing that losses are being monitored and that some form of targets and benchmark is in place.
Other Considerations	There will be much industry development in the future around losses. It is important that TLC has benchmarking targets in place and is aware of what is occurring within the network. The benchmarking targets have been set based on present network configuration and generation injections using an extensive network analysis package. They only relate to technical losses given TLC has no control over non-technical losses that are largely generated by metering error.

TABLE 4.22: JUSTIFICATION FOR NETWORK LOSS TARGETS

4.2.2.2 Network Power Factor

The higher the network power factor the more efficient the transfer of energy. As discussed in other sections power factor becomes a complex issue when the effects of distributed generation are added. TLC set a performance target to maintain grid exit power factors at present levels during transmission interconnection charge periods.

Table 4.23 lists the average power factor targets at grid exit supply points during regional peak periods. The target is based on 2010 national data set by the Electricity Authority and that the existing power flow is maintained.

TARGET POWER FACTOR BY GXP				
Grid Exit Point	**2007/08**	**2008/09**	**2009/10**	**Target Power Factor (Average during RCPD period)**
Hangatiki	0.904	0.905	0.926	0.912
Ongarue	0.916	0.884	0.948	0.916
Tokaanu	0.989	0.993	0.994	0.992
National Park	0.988	0.993	0.989	0.990
Ohakune	0.987	0.994	0.991	0.991

TABLE 4.23 TARGET POWER FACTOR BY GXP DURING RCPD PERIOD

Table 4.24 summarises the justification for power factor performance targets.

JUSTIFICATION FOR POWER FACTOR PERFORMANCE TARGETS	
Item	**Justification**
Consumer Considerations	To encourage demand side reactive power control TLC's demand billing will likely be totally based on kVA demand for all customers once lower cost 2 channel kVA meters become available. Demand side reactive power control is the most efficient location in the power system for power factor correction. The connection of distributed generation reduces grid exit power factor as further detailed in Section 5. Capacity of future DG connections may be limited by their ability to run at unity power factor during RCPD periods. The target is set on the basis that TLC's billing system will encourage demand side power factor improvement. The electricity connection code under the Electricity Governance Rules will mean that customers will likely have to fund more reactive power factor correction in the future.
Statutory Considerations	Reactive power flows reduce network efficiency. All government policy statements focus on improving the efficiency of the electricity supply system. Benchmarking and setting targets to maintain or improve grid exit power factor fits with this objective.
Regulatory Considerations	The electricity connection code under the Electricity Governance Rules place limits on grid exit power factor.
Other Considerations	TLC is committed to ensuring its electricity network is transporting energy as efficiently as possible. Setting a target to maintain or improve grid exit power factor fits with this objective.

TABLE 4.24: JUSTIFICATION FOR NETWORK POWER FACTOR TARGETS AT GXP

4.2.2.3 Network Load Factor

Load factor is an indicator of network investment efficiency, the higher the load factor the more efficient the utilisation is of the assets. Nationally over recent years load factor has been reducing as peak demand has been growing faster than the energy transported. An objective of TLC's demand based billing is to hold load and ideally improve load factor. The target is to maintain or improve on the current load factor of 60%. The Target has been determined by data collected in financial years 2004 to 2010. Historic data gives an average of 62.5% load factor; it is suspected that the financial years 2005-2007 and 2010 had been disclosed inaccurately. The actual average performance was estimated to be around 59%. The target has been set around the assumption that load factor will improve.

Table 4.25 lists the load factor for historic years and the 2010/11 target.

NETWORK LOAD FACTOR: HISTORIC DATA AND TARGET			
Financial Year	**Electricity Volumes Carried (MWhr)**	**Co-incident System Peak (MWhr)**	**Load Factor**
2004/05	314.6	55.6	64.61%
2005/06	317.6	55.7	65.09%
2006/07	329.5	58.4	64.35%
2007/08	327.0	65.0	57.00%
2008/09	319.0	61.0	60.00%
2009/10	354.0	64.0	64.00%
2010/11 Target			**60.00%**

TABLE 4.25 : HISTORIC DATA AND TARGET NETWORK LOAD FACTOR

Table 4.26 summarises the justification for load factor targets.

JUSTIFICATION FOR LOAD FACTOR TARGETS	
Item	**Justification**
Consumer Considerations	The more efficient the operation of the network is the lower the customer charges will be. The target is a benchmark measurement of one of the efficiency indices, demand based billing was introduced to try and improve this performance. The target has been set at the present figure. Over the last few years load factor has been reducing due to demand increasing faster than the energy transported.
Statutory and Regulatory Considerations	Government policy statements require improved network efficiency. As outlined above the reverse trend has been taking place over recent times. The objective of demand billing is to firstly halt this trend and then possibly reverse it.
Stakeholder and Other Considerations	Stakeholders require the best possible returns from the network with the lowest possible charges being passed onto customers. A number of customers are having trouble with the impacts of demand billing and the effects that this has on removing cross subsidies among customers.

TABLE 4.26: JUSTIFICATION FOR NETWORK LOAD FACTOR TARGETS

4.2.3 Asset Effectiveness Targets

The following targets are used to measure asset effectiveness:

- Accidents/Incidents involving network assets.
- The number of asset hazards that are eliminated/minimised annually.
- Diversity factor.
- The ratio of total trees felled to trees worked on annually.

These targets align with corporate strategic objective to renew, develop and maintain a network that fulfils stakeholders' value expectations including their social and environmental responsibilities. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

4.2.3.1 Accidents/Incidents Involving TLC Network Assets

TLC's objective is to minimise the accidents and incidents that are caused by or are associated with its network assets. Table 4.27 lists the performance targets that provide a benchmark for these events.

ACCIDENT/INCIDENT RELATED PERFORMANCE TARGETS	
Event	**Target (maximum events)**
Lost time, injuries with staff and contractor	5
Number of DOL notifiable accidents	0
Number of public injuries on TLC facility	0

TABLE 4.27: ACCIDENT/INCIDENT RELATED PERFORMANCE TARGETS

These targets have been set based on historical data.

Table 4.28 summarises the justification for Accident/Incident targets. These targets are measured by counting the numbers of incidents.

JUSTIFICATION FOR ACCIDENT/INCIDENT TARGETS	
Item	**Justification**
Consumer Consideration	Lost Time; Injuries involving Staff and Contractors: Responsible customers do not support organisations that do not place importance on safety to staff. The target has been set based on previous numbers less a level of improvement. Number of DOL notifiable accidents: DOL notifiable accidents results in an investigation and in the worst case a prosecution; this is a costly and complex process. DOL prosecution costs and fines are substantial and as a result a target of zero has been set. Number of Public injuries involving TLC facility: Responsible customers will not support an organisation that does not have regard for public hazard control. TLC does not want any of its assets to cause public injury and as a consequence a target of zero has been set.
Statutory Considerations	Lost Time; Injuries involving Staff and Contractors: There is no specific legislation that details the lost time injury target. DOL and ACC legislation and the SMS require all significant hazards to be identified and adequately controlled to prevent serious harm. Number of DOL notifiable accidents: Notifying the Department of Labour of accidents results in an investigation and often a prosecution. This is a costly and complex process. Number of Public injuries involving TLC facility: There is comprehensive legislation that focuses on ensuring utilities control, maintain, renew and construct assets that do not cause harm to the public, e.g. safety management system required by the Electricity Act.
Regulatory Considerations	As described under Statutory considerations. Sitting under legislation there are numerous regulations that are focused on ensuring TLC control, maintains, renews and constructs assets that do not cause injury to staff and the public e.g. the Electricity (Safety) Regulations.
Stakeholder Considerations	Responsible and ethical stakeholders want lost time injuries involving staff and contractors, DOL notifiable accidents and injuries involving the public minimised or eliminated.
Other Considerations	TLC wishes to eliminate all accidents/incidents to staff and the public.

TABLE 4.28: JUSTIFICATION FOR ACCIDENT/INCIDENT TARGETS

4.2.3.2 Number of Asset Hazards that are Eliminated/Minimised Annually

Hazard control improvements make up a significant proportion of the renewal expenditure over the planning period. Many of the old TLC assets have hazard issues associated with legacy architecture; TLC's target is to make sure that old equipment is being removed from the network. The targets have been set based on the number of improvements included in the Plan.

Table 4.29 lists the target for removing equipment that has been identified as hazardous during the planning period and included in the calculations of forward expenditure.

TARGETS FOR REMOVING HAZARDOUS EQUIPMENT SITES					
Year	Service Boxes	Two pole Structures	GMT	Switching Equipment	Total Hazards Eliminated/Minimised
2010/11	50	8	2	3	63
2011/12	50	9	3	4	66
2012/13	50	6	3	3	62
2013/14	50	4	3	3	60
2014/15	50	10	4	6	70
2015/16	50	9	3	6	68
2016/17	50	8	4	3	65
2017/18	50	6	4	6	66
2018/19	50	8	7	4	69
2019/20	50	9	5	2	66
2020/21	50	6	3	4	63
2021/22	50	3	3	5	61
2022/23	50	3	4	2	59
2023/24	50	2	5	2	59
2024/25	50	2	4	4	60
2025/26	50	1	6	0	57
2026/27	50	1	5	1	57

TABLE 4.29: TARGETS FOR REMOVING HAZARDOUS EQUIPMENT SITES DURING THE PLAN PERIOD

Table 4.30 summarises the justification for the number of asset hazards that are eliminated/minimised annually. These targets are the numbers of projects included in Plans.

JUSTIFICATION FOR NUMBER OF HAZARDS ELIMINATED/MINIMISED TARGETS	
Item	**Justification**
Consumer Considerations	Responsible and ethical customers will not support an organisation that fails to rectify known hazards. TLC customers require the network to replace hazardous equipment.
Statutory Considerations	Legislation requires TLC to identify and replace hazardous equipment. Commerce Commission and other regulators accept that hazard renewals take priority and have to be completed. An objective of these targets is to ensure Statutory administrators understand that these needs exist and support programmes to remove hazards.
Regulatory Considerations	There are numerous regulations that require TLC to remove hazardous equipment from service. An objective of these targets is to ensure the programmes are locked in, that TLC has recognised hazards exist and these are being eliminated/minimised.
Stakeholder Considerations	Responsible and ethical stakeholders do not want to be part of an organisation that fails to recognise or rectify known or suspected hazards. The targets TLC has set a clear message to stakeholders that hazardous equipment exists and programmes are locked in place to remove this from service.
Other Considerations	TLC has surveyed the network and evaluated all sites that may contain hazardous equipment or be hazardous by their architecture. This process has produced lists of equipment sites that have been included in long term Plans, the various sites have also been included in cost estimates in other sections of the Plan. The actual numbers of sites have been included in the performance targets to ensure overall integration of the various sections of this Plan.

TABLE 4.30: JUSTIFICATION FOR NUMBER OF HAZARDS ELIMINATED/MINIMISED TARGETS

4.2.3.3 Diversity Factor

Table 4.31 lists the historic diversity factor and 2010/11 target

DIVERSITY FACTOR: HISTORIC DATA AND TARGET			
Year	**Sum of Consumers' maximum demands (KVA)**	**Maximum co-incident demand on system (KVA)**	**Diversity Factor**
2008/09	94217	61300	1.54
2009/10	100838	63500	1.59
2010/11 Target			**1.56**

TABLE 4.31: DIVERSITY FACTOR HISTORIC DATA AND TARGET

Diversity Factor is the probability that a particular piece of equipment will come on at the time of the facility's peak load. Diversity can be calculated by ratio of the sum of the individual maximum demands to the maximum demand of the whole system. It gives an indication of how diverse it is when the individual maximum demands occur. Higher diversity means the individual maximum demands are less likely to occur at the same instants, which means a more efficient network asset utilisation. Diversity Factor target is set at 1.56 which is based on historic performances. Billed demand is used as the substitution figures of maximum demands where ICPs haven't got Demand Meters.

As stated in other sections of the plan, TLC separately bills customers for line charges, the largest component of this charge being based on the demand customers placed on the network during control periods.

The diversity factor is a measure of how effective TLC's demand billing programme is. It is an indication that customers have spread their load more effectively. Table 4.32 summarises the justification for use of diversity factor as a performance measure.

JUSTIFICATION FOR THE USE OF DIVERSITY FACTOR AS A PERFORMANCE MEASURE	
Item	**Justification**
Consumer Considerations	Diversity factor is an industry indicy that can be researched by customers. A slowly increasing ratio means that TLC's demand charges are spreading the times peaks are occurring and thus indicating an improving asset utilisation.
Statutory Considerations	There are no Statutory requirements for this target. There is a Statutory objective to maximise asset utilisation and operating efficiency.
Regulatory Considerations	There is no Regulatory requirement for this target. There is a Regulatory intent to maximise asset utilisation and operating efficiency.
Stakeholder Considerations	Stakeholders require revenue to be collected in a consistent and equitable manner and assets to be utilised.
Other Considerations	The target has been set based on present performance. Focus on demand side management will possibly see it improve. A review of TLC's pricing structure may see the ratio reviewed.

TABLE 4.32: JUSTIFICATION OF DIVERSITY FACTOR AS A PERFORMANCE MEASURE

4.2.3.4 Ratio of Total Numbers of Trees Felled to Trees Worked on Annually

Vegetation control is TLC's greatest operating cost. Felling trees as opposed to trimming gives the best permanent solution. The target for the planning period is to keep the fell ratio above 70%, i.e. 70% of all trees or more are felled as opposed to being trimmed throughout the planning period. This target is based on historic achievements.

Table 4.33 summarises the justification for use of the ratio of trees felled to trees worked on target.

JUSTIFICATION FOR USE OF THE RATIO OF TREES FELLED TO TREES WORKED ON TARGET	
Item	**Justification**
Consumer Considerations	Tree cutting is TLC's largest controllable operating cost. The more trees felled and removed permanently from line corridors as opposed to trimming, the lower the long term costs for TLC and customers. The lower the long term costs the lower the revenue that has to be sought from customers.
Statutory Considerations	There are no Statutory requirements for a tree fell rate target.
Regulatory Considerations	There are no Regulatory requirements for a tree fell rate target. There is a Regulatory requirement to have a tree programme that complies with the tree regulations.
Other Considerations	Because tree control is TLC's largest controllable operating cost it is important that some form of measure is in place to give an indication of its effectiveness. Data is available for the last seven years that gives fell rate statistics. The target has been set at 70% based on the performance over the last seven years.

TABLE 4.33: JUSTIFICATION FOR THE RATIO OF TREES FELLED TO TREES WORKED ON TARGET

4.2.4 Lines Business Activity Efficiency Targets

The following targets, which align with disclosed inter-company indices, are used to measure lines business effectiveness. These are aligned to the Commerce Commission's disclosure requirements and indices:

- Operational expenditure ratio.
- Capital expenditure ratio.
- Capital expenditure growth ratio.
- Distribution capacity utilisation factor.
- Return on investment.
- Capital expenditure per total circuit length.
- Capital expenditure per electricity supplied to customers' connection points.
- Capital expenditure per maximum co-incident system demand.
- Capital expenditure per ICP.
- Capital expenditure per distribution transformer capacity.
- Operational expenditure per total circuit length.
- Operational expenditure per electricity supplied to customers.
- Operational expenditure per maximum co-incident system demand.
- Operational expenditure per ICP.
- Operational expenditure per distribution transformer capacity.
- Interruption targets Class B (planned) for planning period.
- Interruption targets Class C (unplanned) for planning period.
- Faults per 100km for 11 kV non SWER.
- Faults per 100km for SWER.
- Faults per 100km for 33 kV.
- Overall reliability.
- Class B reliability (planned).
- Class C reliability (unplanned).

These targets align with the corporate strategy to adjust prices to fund asset renewal out of revenue at a level in line with that seen as fair by the Commerce Commission. The numerical targets for these indices throughout the planning period are listed in Tables 4.34 and 4.35 at the end of this section.

The definitions of these terms are mostly included in the 2008 disclosure requirements. A number of these definitions are less clear and there is a level of resulting subjective and other variances associated with these figures.

It is understood that many of these benchmarking indices will likely change going forward and that the Commerce Commission will likely be consulting on these in the near future.

4.2.4.1 Operational Expenditure Ratio

The operational expenditure is calculated by dividing the total operational expenditure by the replacement cost of system fixed assets and is a ratio disclosed in report MP2 – performance measures in compliance with the Information Disclosure Requirements 2008.

4.2.4.2 Capital Expenditure Ratio

The capital expenditure ratio is calculated by dividing the total capital expenditure on system fixed assets by replacement costs of system fixed assets. This ratio gives a measure of the sustainability of the level of capital expenditure.

4.2.4.3 Capital Expenditure Growth Ratio

The capital expenditure growth ratio is calculated by dividing the capital expenditure – customer connection and system growth by the change in total distribution transformer capacity. This ratio gives, in TLC's case, an indication of the cost and effectiveness of this expenditure along with its ability to produce revenue. (In TLC's case there is a link between transformer capacity and customer charges).

4.2.4.4 Renewal Expenditure Ratio

The renewal expenditure ratio is calculated by taking the capital and operations asset replacement, refurbishment and renewal expenditure divided by the Regulatory depreciation of fixed assets. This gives a measure of how close renewal expenditure is to depreciation.

4.2.4.5 Distribution Transformer Capacity Utilisation

The distribution transformer capacity utilisation factor is calculated by the maximum co-incident demand of the system divided by the total distribution capacity. The objective of this ratio is to give a measure of the effective distribution transformer use. The distribution capacity utilisation factor is not a good measure in a rural network due to the distortion that comes from the need to size transformers to the maximum transformer load (no diversity with other connected customers) and preferred transformer sizes (the next preferred transformer size up has to be used).

The measure has several other inconsistencies, of which the major one is that it compares MW to MVA. This comparison introduces a raft of issues associated with power factor. The index however is one that has been adopted for disclosure and TLC's performance target is to maintain the ratio at present levels throughout the planning period.

4.2.4.6 Return on Investment

This ratio is calculated using the inputs as detailed in Schedule 10 of the Electricity Distribution (Information Disclosure) Requirements 2008. It is a key ratio used by the Commerce Commission in determining an appropriate level of pricing for a lines company. This figure may be subject to change as required by Directors, Stakeholders and Commerce Commission.

4.2.4.7 Capital Expenditure Ratios

All of these ratios are included in the Commerce Commission disclosure comparison tables in report MP2.

- Total circuit length.
- Electricity supplied to customers' connection points.
- Maximum co-incident system demand.
- Connection point.
- Distribution transformer capacity.

They are background comparators that TLC needs to be aware of for comparing performance among lines companies. They are not directly related to issues such as customer service, quality and hazard control. As such, TLC's long term objective is to keep these within a range that conforms to expectations of a network with the issues that TLC is confronted with, (subject to unique legacy geographic and other features/factors associated with the TLC network).

4.2.4.8 Operational Expenditure Ratios

- Total circuit length.
- Electricity supplied to customers' connection points.
- Maximum co-incident system demand.
- Connection point.
- Distribution transformer capacity.

All of ratios are included in the Commerce Commission disclosure comparison tables in report MP2. They again are background comparators that TLC needs to be aware of for comparisons among lines companies. They are not directly related to issues such as customer service, quality and hazard control. As such, TLC's long term objective is to keep these within a range that conforms to expectations of a network with the issues that TLC is confronted with.

4.2.4.9 Interruption Indicators

- Interruption targets Class B (planned)
- Interruption targets Class C (unplanned)

These target forecasts are in disclosure compliance format and reconcile with the earlier customer service focused targets in the earlier parts of this section.

4.2.4.10 Faults per 100km

These target forecasts are in disclosure compliance format and reconcile with the earlier customer service focused targets in the earlier parts of this section.

- 11 kV non SWER annual averages for the forecast 5 years.
- SWER annual average for the forecast 5 years.
- 33 kV annual averages for the forecast 5 years.

Note: Due to the relatively small amount of TLC's network that is underground, only the overhead figures have been included.

4.2.4.11 Reliability

- Overall reliability by SAIDI and SAIFI.
- Class B SAIDI and SAIFI (Planned).
- Class C SAIDI and SAIFI (Unplanned).

4.2.4.12 Operating Cost Per Km and Per ICP

This target is set based on the estimated future operating cost. The line length has been assumed to increase as described in the development plan. The operating costs generally have been assumed to track inflation. Some adjustments have been allowed for changes to Regulatory requirements and expected lower faults costs as the effects of the renewal programmes come through.

The annual increase in the number of ICPs is the average number of new connections over the last 5 years.

4.2.4.13 Faults Per Line Lengths

The targets for these have been set based on the expected changes that will occur with the overall SAIDI and SAIFI targets currently advocated by TLC.

4.2.4.14 Total Interruptions

The target for the total interruptions has been set based on the expected changes that will occur with the overall SAIDI and SAIFI targets currently advocated by TLC. The number of unplanned outages is expected to decrease as a result of the renewal programme; planned outages will increase in order to carry out the renewal programme.

Tables 4.34 and 4.35 list the Lines Business Activity Efficiency Targets for the planning period.

LINES BUSINESS ACTIVITY EFFICIENCY TARGETS 2011/12 to 2018/19								
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Operational Expenditure Ratio	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%
Capital Expenditure Ratio	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Capital Expenditure Growth Ratio (Factor)	$318.64	$143.76	$316.85	$77.41	$214.66	$154.97	$223.25	$169.13
Distribution Capacity Utilisation Factor	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Return on Investment (Note 1)	6.00%	(Note 1: Subject to change as required by Directors, Stakeholders and Commerce Commission)						
Capital Expenditure per Total Circuit Length	$2,123	$1,905	$2,340	$1,615	$1,954	$1,549	$1,767	$1,595
Capital Expenditure per Electricity Supplied to Customers Connection Points	$34	$32	$41	$29	$37	$30	$36	$34
Capital Expenditure per Maximum Co-Incident System Demand	$175,173	$163,426	$208,743	$149,754	$188,386	$155,255	$184,065	$172,779
Capital Expenditure per ICP	$447	$412	$522	$371	$462	$377	$442	$411
Capital Expenditure per Distribution Transformer Capacity	$47	$43	$53	$37	$45	$36	$42	$38
Operational Expenditure per Total Circuit Length	$535	$540	$530	$520	$510	$500	$491	$481
Operational Expenditure per Electricity Supplied to Customers Connection Points	$9	$9	$9	$9	$10	$10	$10	$10
Operational Expenditure per Maximum Co-Incident System Demand	$44,114	$46,360	$47,278	$48,215	$49,169	$50,143	$51,136	$52,149
Operational Expenditure per ICP	$112	$117	$118	$119	$120	$122	$123	$124
Operational Expenditure per Distribution Transformer Capacity	$12	$12	$12	$12	$12	$12	$12	$11
Interruption Targets Class B (Planned) for planning period.	331	331	331	331	331	331	331	331
Interruption Targets Class C (Unplanned) for planning period	800	800	800	800	800	800	800	800
Faults per 100km for 11 kV non SWER	35	35	35	35	35	35	35	35
Faults per 100km for 11 kV SWER	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Faults per 100km for 33 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Overall Reliability (SAIDI)	300	300	300	300	300	300	300	300
Class B Reliability (SAIDI Planned)	97	97	97	97	97	97	97	97
Class C Reliability (SAIDI Unplanned)	203	203	203	203	203	203	203	203

TABLE 4.34 LINE BUSINESS ACTIVITY EFFICIENCY TARGETS 2011/12 TO 2018/19

LINES BUSINESS ACTIVITY EFFICIENCY TARGETS 2019/20 to 2026/27								
	2019/20	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Operational Expenditure Ratio	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%
Capital Expenditure Ratio	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Capital Expenditure Growth Ratio (Factor)	$291.85	$247.16	$245.39	$260.42	$162.05	$205.41	$231.02	$310.93
Distribution Capacity Utilisation Factor	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Return on Investment (Note 1)	(Note 1: Subject to change as required by Directors, Stakeholders and Commerce Commission)							
Capital Expenditure per Total Circuit Length	$1,913	$1,684	$1,649	$1,465	$1,269	$1,503	$1,272	$1,402
Capital Expenditure per Electricity Supplied to Customers Connection Points	$42	$38	$39	$36	$32	$40	$35	$40
Capital Expenditure per Maximum Co-Incident System Demand	$215,453	$197,121	$200,647	$185,289	$166,895	$205,571	$180,793	$207,125
Capital Expenditure per ICP	$508	$460	$463	$424	$378	$461	$401	$455
Capital Expenditure per Distribution Transformer Capacity	$46	$41	$40	$36	$32	$38	$32	$36
Operational Expenditure per Total Circuit Length	$472	$463	$454	$446	$437	$429	$421	$413
Operational Expenditure per Electricity Supplied to Customers Connection Points	$10	$11	$11	$11	$11	$11	$12	$12
Operational Expenditure per Maximum Co-Incident System Demand	$53,181	$54,234	$55,308	$56,403	$57,520	$58,659	$59,821	$61,005
Operational Expenditure per ICP	$125	$127	$128	$129	$130	$132	$133	$134
Operational Expenditure per Distribution Transformer Capacity	$11	$11	$11	$11	$11	$11	$11	$11
Interruption Targets Class B (Planned) for planning period.	331	331	331	331	331	331	331	331
Interruption Targets Class C (Unplanned) for planning period	800	800	800	800	800	800	800	800
Faults per 100km for 11 kV non SWER	35	35	35	35	35	35	35	35
Faults per 100km for 11 kV SWER	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Faults per 100km for 33 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Overall Reliability (SAIDI)	300	300	300	300	300	300	300	300
Class B Reliability (SAIDI Planned)	97	97	97	97	97	97	97	97
Class C Reliability (SAIDI Unplanned)	203	203	203	203	203	203	203	203

TABLE 4.35 LINE BUSINESS ACTIVITY EFFICIENCY TARGETS 2019/20 TO 2026/27

The Lines business activity targets are used mostly for industry benchmarking. TLC focuses on the performance targets outlined in earlier sections and the lines business activity efficiency targets give a measure of the effectiveness of these strategies and allow industry benchmarking. Many of these targets are largely not understood by customers. The Lines Company believes that by working towards the performance targets listed earlier in this section, funds will be used in the most efficient way to provide a level of security and level of charges that satisfies customers. The targets have been set based on both historic figures and forward expenditure predictions. (Note the forward expenditure prediction calculator will be expanded to give more accurate predictions of the latest Commerce Commission indices once these have been finalised.

Table 4.36 discusses the justification for lines business activity efficiency targets.

JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS		
Target	**Item**	**Justification**
Operational Expenditure Ratio	Consumer Consideration	The operational expenditure ratio gives benchmark for customers and intercompany comparisons
	Statutory and Regulatory Consideration	This is a disclosed performance measure. The ratio serves as a comparison between companies and operating periods for economic analysis.
	Stakeholder Consideration	This ratio allows stakeholders to directly compare companies and financial periods.
Capital Expenditure Ratio	Consumer Consideration	The capital expenditure ratio gives an indication of the organisation's capital expenditure strategies.
	Statutory and Regulatory Consideration	This is a disclosed performance measure. The ratio serves as a comparison among companies and operating periods. It gives an indication of the long term sustainability, i.e. the level of capital reinvestment to the replacement cost of the asset base.
	Stakeholder Consideration	This ratio gives stakeholders an indication of the amount of capital expenditure occurring.
Capital Expenditure Growth Rate	Consumer Consideration	The capital expenditure ratio gives an indication of the capital expenditure required per kVA of increased capacity.
	Statutory and Regulatory Consideration	This is a disclosed performance measure. It will give the Regulatory agencies a comparison among companies of the cost of growth. These will differ among companies for a host of reasons including factors such as the steps between investment levels required for marginal capacity increases and historic network architecture issues.
	Stakeholder Consideration	Gives stakeholders intercompany comparisons and an indication of costs of capacity increases.
Renewal Expenditure Ratio	Consumer Consideration	This ratio gives customers some form of measure of the long term sustainability of the renewal expenditure levels.
	Statutory and Regulatory Consideration	As above, except that it will be used as a factor in justification considerations for renewal expenditure. It will also likely be used for intercompany comparisons.
	Stakeholder Consideration	It is likely this ratio would be used as a comparison measure.

JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS		
Target	**Item**	**Justification**
Distribution Transformer Capacity Utilisation	Consumer Consideration	Is an intercompany disclosure measure that most customers will not understand. TLC would not use it as a performance target if it were not a disclosure indice as it is not really suited to comparisons among networks with different rural, remote rural and urban mixes.
	Statutory and Regulatory Consideration	As above. Intercompany measure that can be a misleading indicator.
	Stakeholder Consideration	As above.
Return on Investment	Consumer Consideration	Key indicators for level of pricing. Gives customers the return on investment they are receiving for their stake holding in the company.
	Statutory and Regulatory Consideration	As above. It is a key indicator used by regulators to set or approve the level of pricing.
	Stakeholder Consideration	As above. It is a key index for the "bankability" of the organisation.
Capital Expenditure and Operational Expenditure per Total Circuit Length	Consumer Consideration	These are disclosure comparison indicators. Can be misleading for people using these as indicators as they do not include privately owned lines. Privately owned line distances can be significant. (In TLC's case, 20% of lines are considered private). The definition of privately owned lines varies among lines companies and as such these indices can be misleading.
	Statutory and Regulatory Consideration	As above. Many Regulatory and Statutory analysts do not understand the complexities of these indicators and may misinterpret the figures. The complexity of the ownership issue has been caused by changes to the Electricity Act and its Regulations over many years.
	Stakeholder Consideration	As above.
Capital Expenditure and Operational Expenditure per Electricity Supplied to Customers' Connection Points	Consumer Consideration	These are disclosure comparison indicators. They can be misleading to customers for two principal reasons. These are: The electricity supplied to consumers throughout the industry has a reasonably high level of inaccuracy caused by misread meters and other errors associated with metering. The energy supplied through a network is not directly related to costs.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Capital and Operating Expenditure per Maximum Co-incident System Demand	Consumer Consideration	These are disclosure comparison indicators.
	Statutory and Regulatory Consideration	As above. It is important to understand that the going forward focus of TLC's demand billing is regionally and locally focused. Co-incident demand times may also be different to regional and local demands and as such the usefulness of these indicators can be quickly diluted.
	Stakeholder Consideration	As above.

JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS		
Target	**Item**	**Justification**
Capital and Operating Expenditure per Connection Point	Consumer Consideration	These are disclosure comparison indicators. They are high level indicators that are simpler than some of the others above to understand. Over time they will show trends and give customers a feel of the investments being made per customer.
	Statutory and Regulatory Consideration	High level indicators for intercompany comparisons. They will likely highlight the company's present expenditure strategies and needs.
	Stakeholder Consideration	As above. The indicators give stakeholders and understanding of the investment at an individual customer level.
Capital and Operating Expenditure per Distribution Transformer Capacity	Consumer Consideration	These are disclosure indicators. They are high level indicators that would be difficult for the customer to understand. They also have some distortion effects if they are used to compare urban and rural networks.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Interruption Targets Class B (Planned) and Class C (Unplanned) for the Planning Period	Consumer Consideration	These are disclosure comparison indicators. The numbers of interruptions will go up and down from year to year for a whole host of reasons. They are an indicator indice only. Comparisons among companies are subject to variations caused in definition of interruptions and the like. (The definition in the handbook for example, has a level of misinterpretation variability). Customers may misinterpret this information.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Faults per 100km for 11 kV non-SWER, 11 kV SWER and 33 kV	Consumer Consideration	These are disclosure comparison indicators. Most customers would not understand the difference in voltage or classification, i.e. SWER and non-SWER. These are figures they could use to compare among companies and charges over time. The figures will be influenced by abnormal events when year to year figures are compared.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Reliability: Overall – Planned & Unplanned SAIDI & SAIFI	Consumer Consideration	These are disclosure comparison indicators. SAIDI and SAIFI are international indicators. They are difficult for customers to understand. They are accepted high level indicators, but their downside is well documented in various papers.
	Statutory and Regulatory Consideration	As above. International comparison.
	Stakeholder Consideration	As above.

TABLE 4.36: JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS

Section 5

5. *Network Development Planning*

5.1 Description of Planning Criteria and Assumptions

5.1.1 Introduction

Resourceful network development planning is critical in that TLC has to achieve the best results for its stakeholders and customers, yet still meet regulatory requirements and stay within the bounds of best industry practice.

TLC covers a large geographical area but has a small customer base that results in limited cash flow to fund the development that caters for load growth, achieving agreed customer service levels and providing a network that is stable with minimal outages.

TLC has a 15 year planning window. Each year TLC holds a planning meeting that reviews the proposed Plan and adjusts it as required. The review is based on facts from data collected and knowledge of network performance and where forecasts indicate that network will be constrained, planned customer development and load growth.

The basis for the development of the Plan are detailed in this section, which discusses the assumptions made and the criteria used, prioritisation of development, forecasting methodology and the impact of uncertain development, generation and demand side management.

This section then goes on to give details on the projects planned in the 15 year planning period, with an in-depth description for those projects that will be started in the coming financial year and to a lesser extent those in the following four years, followed by a high-level description of the projects included in the plan for the following ten years, out to the years 2026/27.

5.1.2 Planning Assumptions

5.1.2.1 Performance Assumptions

- Customers will require reliability to the service level targets in Section 4.
- Customers will require service to the levels in Section 4 i.e. restoration times etc.
- Customers will require quality to levels in Section 4.
- Customers will accept pricing compliant with that approved by the Commerce Commission.
- Customers will accept other performance indicator results that are in line with those of other network companies that supply remote rural areas.
- Customers will require the network to be renewed, developed and maintained to be sustainable for the long term; including a hazard controlled network.

These assumptions are compiled from customer feedback. Customers will be consulted in compliance with Commerce Commission Customised Price Path (CPP) requirements to determine the quality standards they are prepared to accept and fund.

5.1.2.2 Economic Assumptions

- The organisation's pricing models (that are set up in compliance with the Commerce Commission requirements) shall be used for evaluating and setting revenue requirements for development proposals. (These models include capital evaluation formulae, rates of return and valuation in line with Commerce Commission guidelines.)
- If customers are not prepared to fund such development the projects will not take place. (Note: For cumulative capacity projects, additional revenue must come from charges in line with Commerce Commission guidelines. In some cases rates may have to be adjusted in a regional charging density area, or for specific customers, to achieve required returns to make investment bankable.)
- Localised pricing models are set up and used to test the economics of most development projects. (The exception is new and upgraded network connections under 200 kVA.)
- Financial commitment will be required from customers before investing to minimise the risks of stranded assets or non-profitable assets.
- Customers in the King Country have a limited ability to pay ever increasing lines and energy charges.

5.1.2.3 Customer Load Growth Assumptions

- Customers are increasing the average household energy load, with the availably of heat pumps, spa pools and numerous electronic devices.
- Customers require a more reliable supply to ensure electronic devices and lighting are not affected by the networks performance.
- Customers' expectations are much higher than those of 10 or even 5 years previously.
- The growth in electronic devices and compact florescent lighting increases the harmonics on the network.

5.1.2.4 Business Environment Assumptions

- Low growth in urban areas. The focus is on renewal and hazard control.
- Some development around urban centres with lifestyle blocks.
- Growth in numbers of holiday homes in the National Park, Taupo Lake surrounds and Ohakune area. (Since 2009 this development has slowed down.)
- Underground conversion in urban centres is customer funded.
- Dairy farming growth will continue but at a slower rate than during the boom years of 2008-2009.
- Generally, there will be on-going farm rationalisation.
- The ski fields continue with on-going development.
- Industrial customers with high power consumption will vary their growth depending on the economic climate. Generally customer expansions are customer funded projects.
- Small business growth has a low growth rate. If any investment is made this will generally be customer funded and planning horizons are short.
- Continued growth of distributed generation. Some proposed hydro generation has been included in this plan and the proposals for wind farm development have been partially included. (Wind farm projects have a high level of uncertainty).

5.1.2.5 Asset Assumptions

- Assets are being run to their upper capacity limits to defer development investment as long as possible. Renewals are the focus for the planning period.
- Environmental and hazard issues on the network are given a high priority.
- Improvement of the ripple control system and metering of customers, to promote Demand Side Management and reduce losses.

- The use of shunt capacitors is being investigated to provide voltage support. This cannot be developed fully until the ripple signal is fully converted from 725 Hz to 317 Hz and systems are implemented to prevent the capacitors interfering with the ripple signal. (Two mobile units however, have been set up to provide emergency network support).
- Continue the promotion of advanced metering that can produce demand data.
- Ensure the network is capable of achieving targeted reliability, quality and hazard control performance.
- Development reliability improvement should be designed to give the maximum improvement to lower or potentially lower performing areas.
- Build enough asset redundancy and back feed options that allow service to be maintained to customers when critical equipment is removed from service for maintenance, such as the annual Transpower outage at Ohakune, or in times of major faults on the network.
- Use simple but innovative ways to minimise development expenditure to alleviate pressure in growth areas. (Modular substations for example.)
- Network architecture to minimise the effects of network surges that can destroy electronic equipment.

5.1.2.6 Data and Network Analysis Assumptions

- Develop data systems to provide accurate regulatory reporting.
- Develop data and information systems to support decisions that align network performance with asset development, renewal and maintenance.
- Continued SCADA development for more detailed data collection and monitoring.
- Network analysis using data collected and the network analysis program load flow program to model future network requirements, harmonic and capacitor models, wind farm models and protection requirements.
- Explore and develop self-healing network technologies, intelligent networks with automatic load shedding and real time monitoring.
- Develop information systems to be increasingly integrated including :
  - » Revenue models compliant with Commerce Commission guidelines.
  - » Financial systems.
  - » Asset data and information.
  - » Billing systems.
  - » Develop data systems to improve customer service information across the organisation, i.e. outage notification systems, metering and relay data, complaints and customers' enquiries, maintenance and capital plans, and other service related activities.
  - » Customer feedback and contact with the organisation.
- Planning and modelling to find ways to complete the necessary network renewals and development at the lowest possible cost.

5.1.2.7 Grid Exit Power Factor Assumptions

It is assumed that the present grid exit power factor requirements during Regional Co-Incident Peak Demand (RCPD) periods will be modified to consider reactive power flows as opposed to the present power factor figure. This will be required if the intent of the government's wish to promote distributed generation is to be fulfilled. (See discussions on distributed generation for more detail on the reasons for this.)

5.1.2.8 Equipment End of Life Assumptions

Equipment end of life disposal is considered when selecting equipment. It is assumed that issues such as SF6 disposal and other toxic substances should be considered when selecting equipment.

5.1.3 Planning Criteria

The planning criteria are focused on ensuring network performance will meet or exceed performance targets as detailed in Section 4. Most of the criteria listed below have a direct effect on the asset related customer service targets, asset performance targets and asset effectiveness targets.

The planning criteria have been aligned to the capital expenditure development categories as required by the disclosure regulations. These are:

- Capital Expenditure: Customer Connections.
- Capital Expenditure: System Growth. (Cumulative capacity)
- Capital Expenditure: Reliability, Safety and Environment.
- Capital Expenditure: Asset Replacement & Renewal.
- Capital Expenditure: Asset Relocation.

The planning criteria of each of these categories are discussed in the following sections.

5.1.3.1 Planning Criteria: Customer Connections

Most of these connection costs are funded by customers via line charges and capital contributions. The designs for these connections are completed to the various regulations and codes of practice that guide the industry.

Transformers are designed to typical industry earthing, strength, hazard controls and security standards. (The layout of these is described in more detail in Section 3.)

The design criteria for underground cables and associated overhead lines are to industry standards. It is an option for customers to own transformers, lines and cable or pay for these assets as dedicated assets in monthly line charges. Customer owned works must meet published standards before TLC will connect. The connections of assets associated with customer connections usually do not have backup security.

Other technical requirements are covered by TLC's Terms and Conditions of Supply, and commercial requirements.

5.1.3.2 Planning Criteria: Customer Connections: Subdivisions

The local body subdivision conditions generally require new subdivisions to be constructed using underground reticulation.

The capacity requirements of new domestic connections are assumed to be typically 5 kVA. (Line charges have a capacity component and customers may choose to vary this assumption to minimise charges.)

More detail of the design criteria for subdivisions is included in TLC's standards.

The key criteria include:

- Fuses at the point of connection to individual customers.
- Cabling to industry codes using industry preferred sizes.
- Low voltage protection on each circuit heading away from transformers.
- Links between low voltage circuit ends if practical.
- Low voltage panels to be insulated and to have transformer isolation and maximum demand indicators.
- High voltage switchgear (ring main type) should be fitted to all but the last spurred transformer. Each transformer and/or spur should be individually protected against over-current.
- Where practical and economic the high voltage cable network will be ringed.
- 11 kV cabling to be industry preferred size cables.
- All overhead to underground cable connections shall have isolation links and surge protection.
- Voltage drops in low voltage cables should not exceed 5% with a co-incident demand of about 5 kVA for domestic installations.
- Typical domestic average 3 hourly demands of 2 to 3 kVA will be assumed.

Experience has shown that when these design criteria are applied, subdivision reticulation will perform to the targets in Section 4 and hazards are controlled to acceptable standards.

TLC may model subdivisions using a pricing model or use standard criteria for the amounts it requires customers to fund. The standard criteria are for TLC to supply the transformer assets and for the developer to fund the remainder.

5.1.3.3 Planning Criteria: Customer Connections: Industrial Connections

Industrial connections are usually tailored for the customers' individual needs. Options like alternative supplies and additional security are discussed with customers and when necessary pricing models are developed to give customers cost implications. Capacities are tailored to customers' requests.

Design criteria that are not affected by customer requirements include:

- Earthing to industry standards.
- The need for all ground level components to be insulated, protected, and earthed to acceptable industry hazard control standards.
- The need for all equipment to be secure and have advanced hazard control features.
- All designs must meet or exceed industry hazard control standards.
- Installations designed to ensure voltage drops are less than 5%.
- Harmonics and voltage flicker to comply with NZECP36 and AS/NZS 61000 series of joint Australian and New Zealand standards.
- Surge suppression fitted to all 11 kV or 33 kV points of connection, (11 kV – 9 kV, SWER 11 kV – 18 kV and 33 kV – 27 kV arrestors respectively).

Experience has shown that designs to these criteria will meet network performance targets. (As outlined in Section 4 and in the assumptions above)

5.1.3.4 Planning Criteria: Customer Connections: Distributed Generation Connections

Distributed generation connections greater than 10 kVA are usually tailored for the customer's needs and the specific installation. Installations below this capacity level are likely to have insignificant effects. (This may exclude inverter connections on SWER or weak systems.)

The physical design criteria are as for small customer connections and industrial connections (dependant on the size of the installation). The additional design criteria include:

- Capacity: Capacity is determined by the maximum voltage rise at the point of connection that will not affect other customers. (Normally 11.2 kV on 11 kV system and depends on the tapping range of 33 kV zone substation transformers on the 33 kV network) at RCPD periods whilst maintaining a unity power factor injection.
- Protection: Protection to be set to ensure no damage to other customers and TLC's equipment.
- Power Factor: Equipment to be set to produce unity power factor during RCPD periods.
- Voltage: Voltage protection to be set to ensure generation trips when voltage varies typically more than ± 10%.
- Frequency: Frequency protection set to trip slightly outside the reach of national automatic under frequency load shedding (AUFLS) relays.
- Fault levels: Additional generation must not cause combined network fault levels that exceed the rating of existing equipment.
- Harmonics: Compliance with NZECP 36.
- Voltage flicker: Use of guidelines as in AS/NZS 61000 series.
- Reliability: Customers have to accept the reliability of existing lines. If they require a better level of reliability or security they have to fund this.
- Auto-reclosing: Connections have to be engineered to be able to withstand line auto-reclosing.
- Charges: In compliance with the Electricity (Distributed Generation) Regulations.

5.1.3.5 Planning Criteria: System Growth

As with new connections, system growth has to be funded from the additional income such investment creates. System growth is also closely related to security and reliability. Installing n-1 capacity and alternative supplies have to be funded by those who benefit from it either directly or through on-going revenue. Planning criteria for system security is in many ways embodied in the service level structure that specifies performance targets based on TLC's financial and logistic ability to deliver security of supply. There is, for example, a natural tendency to prioritise security for areas in the north of the network where there is a higher concentration of industrial customers and hence greater consequences of loss of supply as well as greater revenue to fund investment.

Funding growth from additional revenue forces the development and the criteria associated with it to be more focused.

5.1.3.6 Planning Criteria: System Growth: Modular Solutions

The planning criteria have to focus on the specific performance issues.

For example:

- Modular low cost substations that address capacity for 10 to 15 years as opposed to expanding existing sites or establishing large new ones with inherently greater long term capacity. (There are other advantages to the modular approach including diversification that improves reliability and control of fault currents.)
- Installing modular modern equipment such as switchgear in existing sites.
- Installing regulators and the like in the existing network to push the capacity of the existing assets.
- Tuning voltage levels and active/reactive power flows in the existing network to extend capacity. (This is often done in conjunction with distributed generation installation.)
- Modular break-up of SWER systems when the loading of existing configurations becomes high to the point that the operating earth potential rises are hazardous.
- Supplying SWER systems off three phase systems to use phase displacements to reduce earth currents.
- Incentives for customers to control their reactive power needs.

The equipment used must be:

- Standard and be able to be swapped to different sites.
- Simple to install, operate and maintain.
- Installed in such a way that it is easy to operate and repair.

Network capacity increases are designed to integrate and form long term solutions.

The technology chosen must form part of a longer term integrated solution. For example, regulator controllers must have the capability to control capacitor banks and reclosers must be able to provide synchronised switching. Both of these will be necessary as the network is further tuned and operated in a more automated and complex mode in the future. Equipment with these features can be supplied "off the shelf" at no extra cost.

Note: The installation of cable, conductors and equipment must take into account the fault levels on the network. Any new distributed generation application must consider the effect of the connection to TLC's network and local fault levels. (As noted above)

5.1.3.7 Planning Criteria: System Growth Funding

There are a number of areas in the network where the present revenue is not funding present operating and renewal costs. In these cases there is no additional income available to fund the modular incremental costs. As a consequence some areas within TLC's network are charged a connection fee based on the kVA load applied for, to provide funding towards securing upstream capacity and reliability in those areas. (For example, in the Mokau and Whakamaru regions, there is a capacity charge added to every new connection to the Network.)

These amounts are determined after detailed analysis using a pricing model based on the Commerce Commission's regulatory valuations and rates of return. As stated in other sections growth has to be self-funding.

5.1.3.8 Planning Criteria: System Growth: Security

The TLC network is relatively complex and there are few places where there is n-1 full capacity security. The design criteria intent is to have medium and light load backups for zone substations and in as many parts of the of the 11 kV network as practical with no or minimal cost. Section 3 gives more detail on the effectiveness and implementation of these criteria.

This plan includes a number of projects that create security improvements as a by-product of environmental, hazard control and other targets. The security implications of each development project are looked at on a case-by-case basis and related back to the performance criteria in Section 4.

The modular solutions discussed above are installed in such a way that at medium to light load times there is a backup supply. (For example, if a modular substation fails there is diversity such that other assets in the area can continue to supply customers.) TLC does not use probabilistic security planning techniques.

5.1.3.9 Planning Criteria: System Growth: Power Quality

Analysis of the power quality is included in the design criterion for system growth. This includes the investigation of voltage complaints, voltage surges, voltage and current studies and power factor and harmonic studies.

This satisfies the performance criteria outlined in Section 4 for power quality in maintaining regulatory requirements for voltage levels and ensuring current ratings of existing assets are not compromised.

5.1.3.10 Planning Criteria: Reliability: Safety and Environmental

5.1.3.10.1 Planning Criteria: Reliability

A plan to improve reliability was embarked on in 2003. Reliability planning initiatives are aligned to focus on achieving the asset related customer services targets, asset performance targets and asset effectiveness targets as detailed in Section 4.

The criterion is to increase automation of network tie points and the installation of reclosers where there are relatively long spurs with a significant number of customers. The more critical locations, such as areas with long response times due to travelling time for fault personnel, are given priority and completed first.

Reliability is also a by-product of other design criteria and will change as hazard control and renewal works are completed. Outage data are also analysed and problem areas targeted.

All work for reliability and automation are planned with the future intention of developing a self-healing Network with automated load shedding.

5.1.3.10.2 Planning Criteria: Safety (Hazard Control)

Network hazard related control has two important streams. The first is about design and equipment selection to minimise the inherent network hazard levels. The second is the operation and maintenance of this equipment. Operation includes procedures, competence and the use of personnel protective equipment (PPE). Conceptually, design criteria being applied require two to three levels of incompetence or a concerted effort to break into a piece of electrical equipment before contact is made with energised equipment. TLC aims to minimise hazard related risks and operate a network that is considered to have reduced hazards to a tolerable level.

Arc flash analysis of equipment is carried out using the network analysis programs arc flash modules and appropriate signage installed for PPE requirements and procedures.

Two performance targets detailed in Section 4 are targeted specifically at hazard elimination by removing and replacing hazardous equipment and consequently minimising and eliminating accidents. Details of plans to achieve this are included later in this section.

5.1.3.10.3 Planning Criteria: Environmental

The planning criteria for environment projects are:

- End of use disposal must be considered.
- Risk of release of hazardous substances into the environment must be minimised or eliminated.
- Equipment must be able to withstand earthquakes.
- Transformer bunding and oil containment.
- Equipment must be out of Lahar paths and flood zones if possible.
- Equipment must be selected so that as far as practical it will operate through periods of volcanic ash fallout.
- Equipment must be selected that can withstand fertiliser applications in rural areas.
- Network designs should consider losses and decisions to increase losses should be avoided if possible.

Experience has shown that if equipment can perform under these environmental conditions the network performance targets will be achieved. (See Section 4)

TLC's western coastal assets are subject to salt laden air; therefore, assets are chosen that perform well in this environment. Due to the high numbers of rural properties that apply fertiliser along with a number of lime works that create excessive dust deposit on insulators and equipment, TLC's standards and equipment selection specify components that are designed for high pollution environments. Other factors that TLC's designers take into consideration are ways of minimising the effects of a polluted environment.

The photograph in Figure 5-1 illustrates an 11 kV switch installed in a relatively polluted environment at a lime processing works. The switch is inside a shed with a dust cover designed to fit over the switch to minimise the dust contaminating the equipment. (Dust cover bunched up on top of equipment in this photo).

FIGURE 5-1: 11 KV SWITCH WITH DUSTCOVERS INSTALLED AT A LIME WORKS

Thermal areas, such as Tokaanu, require components that can be installed in hot ground. In one case TLC obtained special dispensation to not follow Taupo District Council District plan for underground reticulations in urban areas, as the ground was too hot for an underground cable. TLC also had to install wooden poles due to the corrosive nature of the gases in the thermal area that reduce the life of concrete poles.

5.1.3.11 Planning Criteria: Asset Relocation

Asset relocations are mostly associated with road works and other infrastructure activities. There are also a number of cases where assets have to be moved around slips or other environmental events.

The criteria for these types of works are to:

- Relocate assets as required by road controlling authorities.
- Renew assets while on site as per renewal policies.
- Reinstate the asset with similar capacity as previously.
- Secure funds from road controlling authorities in compliance with acts and regulations.
- Obtain land access easements for relocated works.

Experience has shown that following these criteria will achieve the performance targets as detailed in Section 4.

5.1.3.12 Planning Criteria: Asset Replacement and Renewal

Asset replacement and renewal means the capital expenditure associated with the physical deterioration of existing Network assets. Section 6 provides full details on the criteria for managing the asset replacement and renewal programme so that the asset is restored to its original service performance level.

The primary criterion for renewal is hazard control, the secondary criterion is to renew aged assets at the end of life.

5.1.4 Capacity Criteria for Selecting New Equipment for Different Types of Assets or Different Parts of the Network

The capacity of components and sections of the network is considered when planning developments. Each project has to be designed on a case by case basis to verify that the capacity requirements are achieved and that TLC's design standards and AS/NZS 7000:2010 Overhead Line Design – Detail Procedure are adhered to in order to ensure asset performance, efficiency and effectiveness targets are met. (Note: TLC design standards are based on Acts, Regulations, Codes and industry best practice.)

TLC network analysis program, ETAP, is configured to represent the predicted growths as illustrated in the demand forecast tables in Section 5.4. Network models are run with the predicted loadings; this allows TLC's planners to factor future capacity requirements into their equipment selection for the growth anticipated.

For design purposes TLC considers the end of the planning period forecast capacity requirements in normal operation and contingent operation; the rating or size selected generally is one size greater than normal operation, which allows for contingent operation.

In technical terms this means:

5.1.4.1 33 kV Lines

5.1.4.1.1 Conductor

New conductor is sized taking into account the end of the planning period load and common industry sizes. Unless information exists that indicates a different approach is justified, one size up from that which will meet the end of planning period load is chosen. The conductor size is selected for both electrical load and mechanical strength. Typically, the conductors used are Ferret, Mink, Dog, and Jaguar. (Smaller conductors cannot be used in some locations because of their inability to withstand fault currents.)

Future power-flows are modelled using the network analysis program to ensure that predicted growth is catered for by the selected conductor size. (This includes any likely network layout changes).

5.1.4.1.2 Poles

Poles are selected that have the mechanical strength to withstand wind and ice loadings as detailed in codes and modified when necessary to meet local conditions. Both concrete and wooden poles are used.

Wooden poles have better dynamic loading capabilities and are lighter, allowing smaller helicopters to be used to carry them to remote sites. They do twist, however, on drying. Concrete poles do not twist and are better for static loadings but are more expensive and heavier than wooden poles.

The line design software package, "Pole-n-Wires" is used to analyse forces and loadings to ensure the correct pole and stay options are selected.

5.1.4.1.3 Insulators

Insulators rated for high pollution environments are selected. In practical terms, this means 44 kV rated insulators with long creepage distances, and of such a height that magpies have about 100 to 150 mm clearance to the conductor when standing on top of a cross arm. (This includes any likely network layout changes).

5.1.4.2 33 kV Cables

5.1.4.2.1 Conductor size

The next regularly used conductor size up from that required to meet the end of the planning period load. The conductor and screen size is selected for both load and fault current rating. Cabling generally is installed in ducting to allow future replacement and, accordingly, must be de-rated in carrying capacity.

Future power flows are modelled using the network analysis program to ensure that predicted growth is catered for by the selected conductor size. (This includes any likely network layout changes).

5.1.4.2.2 Terminations

Terminations must have high impulse withstand voltages and be of a design that minimises the risk of discharge between cores that cross each other in the termination area.

5.1.4.2.3 Surge Arrestors

All 33 kV cables must be protected by riser, or better, class of arrestor. They should be rated at 27 kV to minimise network surge levels. This criterion is required to meet network quality targets.

5.1.4.3 Zone Substations

5.1.4.3.1 Structures and Enclosures

All equipment that is not security fenced and is below 5.5 metres above ground must be insulated or bonded to earth.

All structures should be built robustly and be capable of handling fault currents and mechanical loadings.

The structure must be arranged so that modular extensions can take place and transformers can be easily swapped between sites.

5.1.4.3.2 Transformers

Transformers should be sized to provide supply to the present load and be arranged to restrict the fault current in the 11 kV network. (Experience has shown that the TLC 11 kV network cannot withstand fault levels of typically greater than 80 to 100 MVA.) Where it can be justified, transformers are sized to provide back-up for adjacent loads.

Transformers and their associated equipment must be arranged so that they can be moved from site to site.

5.1.4.3.3 Switchgear

Switchgear must be simple and able to carry the load and predicted fault currents until the end of the planning period at the least. Typically, most commonly available switchgear is rated above the loadings on the TLC network. Industry standard equipment is purchased.

Preference is given to equipment that is oil and gas free and is made of materials that can be recycled.

5.1.4.4 Distribution Lines

5.1.4.4.1 Conductor

The conductor capacity shall be the next preferred size above that currently required to carry the load and provide adequate voltage. The typical conductor sizes used are Magpie, Flounder, Ferret, Mink, Dog, and Dingo. (Fault currents often restrict the use of smaller size conductors.)

Forecast loadings on the feeders are checked using the network analysis program to ensure that predicted growth is catered for when selecting conductor size.

5.1.4.4.2 Insulators

Short creepage distance insulators have proved unsuccessful due to fertiliser pollution. Replacement with longer creepage distance 11 kV insulators is being undertaken as part of line renewal programmes or as a result of faults. The insulator chosen must be rated for high pollution levels.

On SWER systems, 22 kV insulators (13 kV to earth rating) as a minimum are being used as renewal/replacement is progressed.

5.1.4.4.3 Poles

Poles of adequate strength should be used to comply with codes and be capable of withstanding the area ice loading. A mixture of wood and concrete is used. Wooden poles are selected for their dynamic loading and weight attributes. Weight is important as it allows smaller, lower cost helicopters to be used to place poles in rugged country.

The line design software package, "Pole-n-Wires" is used to analyse forces and loadings to ensure the correct pole and stay options are selected.

5.1.4.5 Distribution Cables

Distribution cables should be sized adequately for their intended purpose e.g. subdivision strength, feeder strength, heavy feeder strength. Cables must also be suitable for carrying the available fault current and industry standard sizes should be used.

Forecast loadings on the feeders are checked using the network analysis program to ensure that predicted growth is catered for when selecting the conductor size.

Termination design should ensure that an earthed screen is under all cross points in cable termination areas.

Where possible all 11 kV cables should have a back feed option. It is recognised that this is sometimes not achievable or cannot be justified as customers are not willing to pay for it.

Arrestors should be installed on cable terminations. These should be riser class or better, and rated for 9 kV for 11 kV single phase and three phase, and 18 kV for 11 kV SWER lines. The objective of these arrestors is to stop equipment damage and control network surge levels.

5.1.4.6 Distribution Transformers

Transformer capacity is based on the preferred size to meet present needs. The use of ground-mounted transformers should be minimised due to the high maintenance costs and the on-going security risk they create. However pole mounted transformer structures for 100 kVA and 200 kVA transformers require extra strengthening and staying to withstand earthquakes. Pole mounted transformers should be protected with distribution class 9 kV surge arrestors to minimise damage and control network surge levels.

5.1.4.7 Distribution Switchgear

Distribution switchgear shall have a capacity and fault current rating suitable for the expected lifecycle. The planning policy for new subdivisions requires the use of ground mounted switchgear and oil RTE switches at alternate sites. This is to minimise costs while ensuring that cables can be easily isolated and earthed.

Reclosers should have synch check and automatic opening during under or over frequency events. (The synchronise function ensures compatibility with future distributed generation connections in the network.)

Pole mounted equipment requires distribution class surge protection to minimise damage and control network surge levels.

5.1.4.8 Low Voltage

Low voltage systems are generally rated at 2 kVA to 6 kVA (typically 5 kVA) per domestic connection. TLC policy is to avoid over-dimensioning installations so as to minimise the risks of stranded assets or excessive asset values that must be funded by customers.

Low voltage renewal work is in the plan, but only work to remedy hazardous installations or work incorporated into the 11 kV line renewals can be justified unless there is a significant customer contribution.

5.2 Prioritisation Methodology Adopted for Development Projects

The development and operation of assets is constantly being monitored and researched. This continuing quest to understand asset requirements to meet customer service levels, leads to a prioritisation methodology that is focused on controlling risk.

This includes:

- A feasibility study and assessment of the project.
- Consequences of not doing the project.

Figure 5-2 illustrates the process for prioritising risk driven needs.

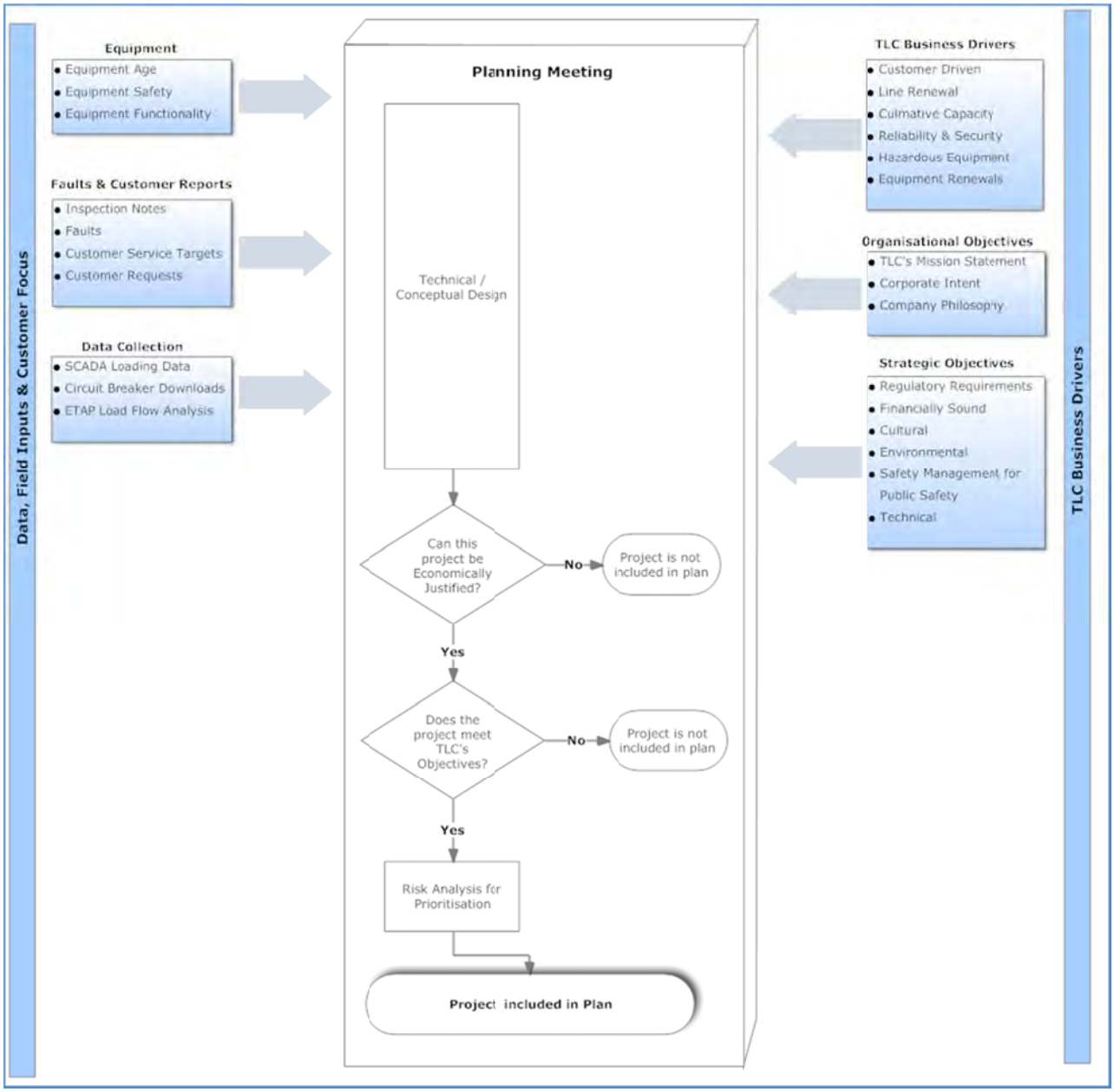


FIGURE 5-2: PLANNING METHODOLOGY

Figure 5-3 illustrates the process for prioritising risk driven needs, and Table 5-1 provides more details/guidelines on how the risk assessment across the project sets is undertaken.

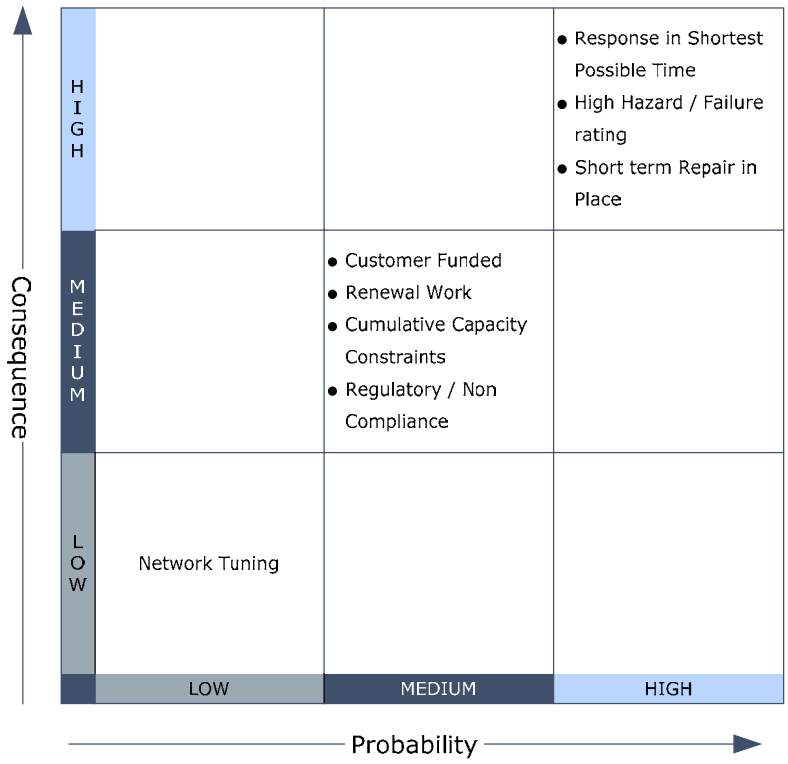


FIGURE 5-3: PRIORITISATION MATRIX FOR RISK DRIVEN NEEDS

The guidelines that are used in applying this approach include:

- Hazard elimination/minimisation, system security/reliability, growth demands, and environmental factors, the impact that a project may have on its customers, the security of supply, the urgency of the project, the resources availability to carry out the project and the impact on compliance.
- A sudden unplanned event can have a follow through effect on the prioritisation of projects and risk assessment is required in the planning of the projects. Any event that jeopardises TLC's ability to maintain their customer service levels and customer expectations needs to have a high priority (especially hazard control and SMS related activities).
- Customer Driven projects where the customer has a deadline that they wish to adhere to.

TLC has developed a database that enables planners to store planning and design notes, a time scale, cost estimation, and the options that have been considered for each project that is included in the 15 year plan. This database also enables the network planner's easy adjustment of the time scale as required.

Ranking	Guidelines	Alignment with Company Objectives
High Consequence High Probability	» Response required in a shortest possible time to mitigate catastrophic failure. » High probability of hazard control breaches and or issues.	Renew, develop and maintain a network that does not exceed 300 SAIDI minutes or 4.86 SAIFI interrupts.
	» Short term temporary repair in place that has marginal hazard control features and if failure occurs there will be significant reliability / security and customer service problems. » Environmental damage event	Renew, develop and maintain a network that is considered non-hazardous by customers and professionals.
Medium Consequence Medium Probability	» Customer funded work that is needed for business or lifestyle activities.	Objectives above plus:
	» Medium hazard control risks. Examples are old fashioned metal switchboards, inadequate but secure barriers etc. » Equipment or sites that have the potential for environmental damage. » Cumulative capacity constraints.	Renew, develop and maintain a network that meets customer quality and reliability expectations.
	» Equipment with legacy legal and statutory non-compliance issues. » Medium risk of equipment failure. (For example lines that are on a slow moving slips). » The overall renewal programme work. » DSM programmes. » Reliability improvement projects.	Renew, develop and maintain a network that fulfils stakeholders' value expectations including their ability to pay and long term tenure, social and environmental responsibilities.
Low Consequence Low Probability	» Network tuning for long term sustainability i.e. regulator settings, distributed generation settings, phase loadings etc. » Harmonic and power factor control programmes » Other non time dependant projects that have been present for many years. (For example reducing current levels on overloaded SWER systems).	Minimising costs and improving efficiency through innovation

TABLE 5-1: SUBJECTIVE/OBJECTIVE ANALYSIS GUIDELINE FOR PRIORITY SETTING

5.2.1 Discussion on how Risk Assessment across the proposed set of projects is undertaken

5.2.1.1 Customer connections

The organisation will borrow to meet the cost of customer work. Commercial arrangements entered into with customers will be negotiated to ensure they can be financed from borrowing and comply with Commerce Commission requirements.

Where customers are paying for a connection that is critical to their enterprise or lifestyle expect service, projects are prioritised based on this customer requirement. There is no other subjective/objective analysis used. The risk of not providing this service is high, i.e. customers will complain and take action against the organisation. This sets the priority.

This is aligned with the need to fulfil stakeholders' value expectations including their ability to pay and long tenure, social and environmental responsibilities.

5.2.1.2 System growth

Network growth is monitored by the collection of information on a number of growth factors.

These include:

- New and increased load applications and the size of load required.
- Subdivision growth.
- Industrial growth applications are dealt with by an account manager.
- Feeder loading.
- GXP and distribution generation figures.
- Transformer numbers installed and the capacity of those transformers.

These objective data are used in growth forecasting and the resulting figures used in TLC's load flow programme to anticipate capacity constraints on the network. The data are subjectively checked and from time to time and figures have to be adjusted based on local knowledge.

The background of the subjective forward loading estimates is outlined in the forecasting section. Quality of supply is closely related to system growth and projects are prioritised in a similar manner. Projects are objectively prioritised based on data. For example, data are collected using SCADA figures, switch history data, a live line power quality meter and other instruments. These data are reconciled with the network analysis package and the worst issues affecting the greatest numbers of customers on a frequent basis are given the highest priorities. These are considered to have the greatest risk.

There is an element of subjective analysis included in predictions and designs based on engineering knowledge of harmonic and voltage flicker implications. Specifically it is known that lightly loaded distribution SWER systems will resonate in the 400 to 700 Hz range and that industrial equipment is often affected by sudden voltage variations of greater than 10%.

Planned work involves ensuring the customers' points of connection have a power quality that complies with regulatory requirements. Some quality of supply projects will be funded by additional customer charges or contributions. A number of other inherited problems have been identified by load flow analysis and will have to be funded from standard revenue.

Power quality is also improved as a by-product of work carried out to improve hazards, and reliability. It is also factored into development work. Capacity and quality improvements are prioritised by the network performance targets. The targets will be compromised if the improvements are not completed and the ability to increase revenue will be hindered. (The network growth included in this plan assumes revenue increases.) This aligns with the objective to renew, develop and maintain a network that meets customer quality and reliability expectations.

5.2.1.3 Reliability, Safety (Hazard Control) and Environment

5.2.1.3.1 Reliability

The reliability improvement strategy approved in 2003 analysed and produced a list of reliability options based on costs per customer minute. These have been reviewed each year and where necessary updated.

The list forms the basis for the objective review of reliability improvement projects, and is included in Table 5-2.

Item	Cost per Customer Minute
Substation Automation	0.01 to 0.07
Downline Breaker and Switch Automation	0.04 to 0.06
Automation Associated with Grid Exit Restoration	0.04
Tree Trimming	0.08
Additional Ties Between Feeders	0.15
Low Voltage Back Feeds	0.11

TABLE 5-2: SUMMARY OF IMPROVEMENTS COST ANALYSIS

Data from previous outages, customer numbers, network architecture and asset condition are used to make both subjective and objective predictions on the reliability and economic impact projects will make.

The objective and subjective work has been used to set priority for automation reliability improvement projects through to 2027. The majority of the discretionary network development projects included in the planning period are focused on reliability improvement work. Priority is given to projects in areas where there have been network performance problems, or it is obvious that there will be issues in the near future. Remoteness from depots and the length of time required to mobilise staff is also considered.

For example: Automation projects in the plan are included that target urban and rural areas. The urban projects have become necessary because the renewal programmes are moving further out into the rural areas. There will be extended periods of time when staff will not be available, i.e. they will all be working out in the remote areas. If a fault occurs in an urban area it will take some time for staff to relocate. The solution to this is to increase urban area automation.

Reliability improvement has been capped at levels that will cement the corporate objective to renew, develop and maintain a network that does not exceed the targets of 300 SAIDI minutes and 4.86 SAIFI interruptions.

5.2.1.3.2 Hazard Elimination/Minimisation

Projects associated with reducing the risk of high consequence, high probability events have the highest development priority. These projects are further prioritised in the order of:

1. Hazard elimination/minimisation
2. Environmental
3. System security/capacity and reliability
4. SMS impact.

This is aligned with the requirement to own and operate a hazard controlled and compliant network. (It also needs to be recognised that hazard elimination/minimisation projects enhance environmental, system security, capacity and reliability issues and vice versa.)

An example of a high consequence, high probability risk SMS minimisation project would be the upgrading of energised equipment that can be accessed, without undue force or effort, by members of the public. A number of these have been addressed over the last few years; however, getting the outages needed to upgrade equipment is often dependent on parallel projects.

The network was originally constructed under budgetary constraints and less rigorous hazard control regulations leading to inherited hazard issues. The slow development of the area has meant that many of these sites have not been upgraded as part of evolutionary network development.

Contributors to identification and evaluation of hazards include:

- Simple obvious problems with equipment.
- Industry accident reports.
- The various acts, regulations, codes etc. that control the industry.
- The application of engineering principles on how equipment operates, and the associated risks.

The experience from investigating and being involved in various industry incidents is used to add a practical aspect to the outcomes of the objective analysis. Over 400 sites have been assessed for hazards by a qualified engineer and electrical inspector/technician as part of the preparation of this plan. Priority has been assigned to those works that remedy hazards and these have been included in the forward renewal and maintenance projections in the plan.

This priority is aligned to the business objective for a hazard controlled, sustainable network and SMS compliant.

5.2.1.3.3 Environmental

Substation inspection data highlight pending environmental risks and concerns. The objective of priority setting includes analysing these data. An example is that the existence of bunding, oil separation and earthquake constraints is identified.

The subjective analysis is associated with the impact of the likelihood of an oil leak or a transformer falling over in an earthquake. When issues are found, the risks are assessed and improvements programmed in accordance with the prioritising methodology and guidelines.

The long term plan includes a number of environmental projects with medium priority. High priority issues such as oil leaks in sensitive areas are addressed sooner than the medium term projects. This aligns with

the objective to fulfil stakeholders' value expectations, including their ability to pay, long term tenure, social and environmental responsibilities.

The long-term renewal programmes include projects to improve oil separation or other environmental facilities. Oil separation and earthquake restraints are also brought up to modern standards when other major work at a site is undertaken.

Environmental factors are considered with most projects. These include:

- End of life disposal issues. The use of SF6 gas insulated equipment is avoided where possible. Recyclable materials and equipment are given priority.
- Compliance with Resource Management Act.
- Minimal cutting of natural vegetation.
- Solutions to minimise environmental impacts, particularly in the National Parks and on sensitive Maori land.
- Impact of natural events on assets.

At this time, system losses are not a direct commercial consideration in direct network cost benefit studies. (The benefit of this flows on to the retailers, while the extra cost of more extensive upgrades cannot be recovered from customers.) It is however recognised that retailers and TLC source income from the same customers that are connected to the TLC network. The regulatory bodies are also increasingly encouraging to networks to control losses even though in TLC's case they are commercially decoupled. (The only coupling is that losses add to demand charges.) As a consequence TLC has invested in understanding the loss implications and is considering the implications in planning decisions. (See earlier sections.)

The objective analysis of losses includes the use of network data, power flow analysis and reconciliation data. The subjective element of analysis includes the estimates for missing data and the varying generation/load assumption used in power flow studies.

TLC does not convert overhead systems to underground unless the customers are prepared to pay the difference between undergrounding and the expected renewal costs associated with TLC maintaining the present system, or some other funding mechanism is established. A section of the Turangi low voltage is an example where an outside funding mechanism has been used to change a project from upgrading the aging overhead system, which also has a number of tree issues, to an underground system.

Undergrounding, however, will be undertaken where it is no longer practical to have an overhead or the cost of an underground system is lower than the renewal of overhead system. Typically this results in short lengths of cable around obstacles. The tree in Figure 5-4 is one example of a short length of cable installed to remove the overhead wire that went through the middle of the tree; the tree had been trimmed to accommodate the conductor.

FIGURE 5-4: LINES THROUGH MIDDLE OF TREE

5.2.1.4 Asset replacement and renewal

Section 6 describes the more general renewal programme and the way the work is prioritised. The subjective element of replacement and renewal is associated with the knowledge and experience to know how long a piece of equipment can continue to give reliable service. The objective elements are things like test results, calculations, measurements, data on failures and economic analysis of the cost of renewal as opposed to continuing to maintain.

TLC tests pole and carries out other tests such as corona discharge and oil tests to maximise the objective component.

The subjective component is also made as consistent as possible by always trying to use the same staff to make calls. Various reviews also take place before and after jobs to determine how accurate any subjective calls made were. For example, old poles are checked after removal to confirm earlier inspection and test results. Renewal work aligns with the objective to meet customers' quality and reliability expectations.

5.3 Demand Forecasts

5.3.1 Introduction

To operate TLC's Network efficiently, and to ensure maximum security and network stability, TLC needs to forecast:

- Loadings on TLC's Network with sufficient accuracy and for a sufficiently long forward period to enable it to plan the development of the Network.
- Demand imposed on each busbar from which it takes supply, or proposes to take supply, from Transpower's Network.
- The effects of proposed generation on TLC's Network.

The forecasts are used extensively in the planning and prioritisation of work proposed on the Network.

5.3.2 Forecasting Methodology

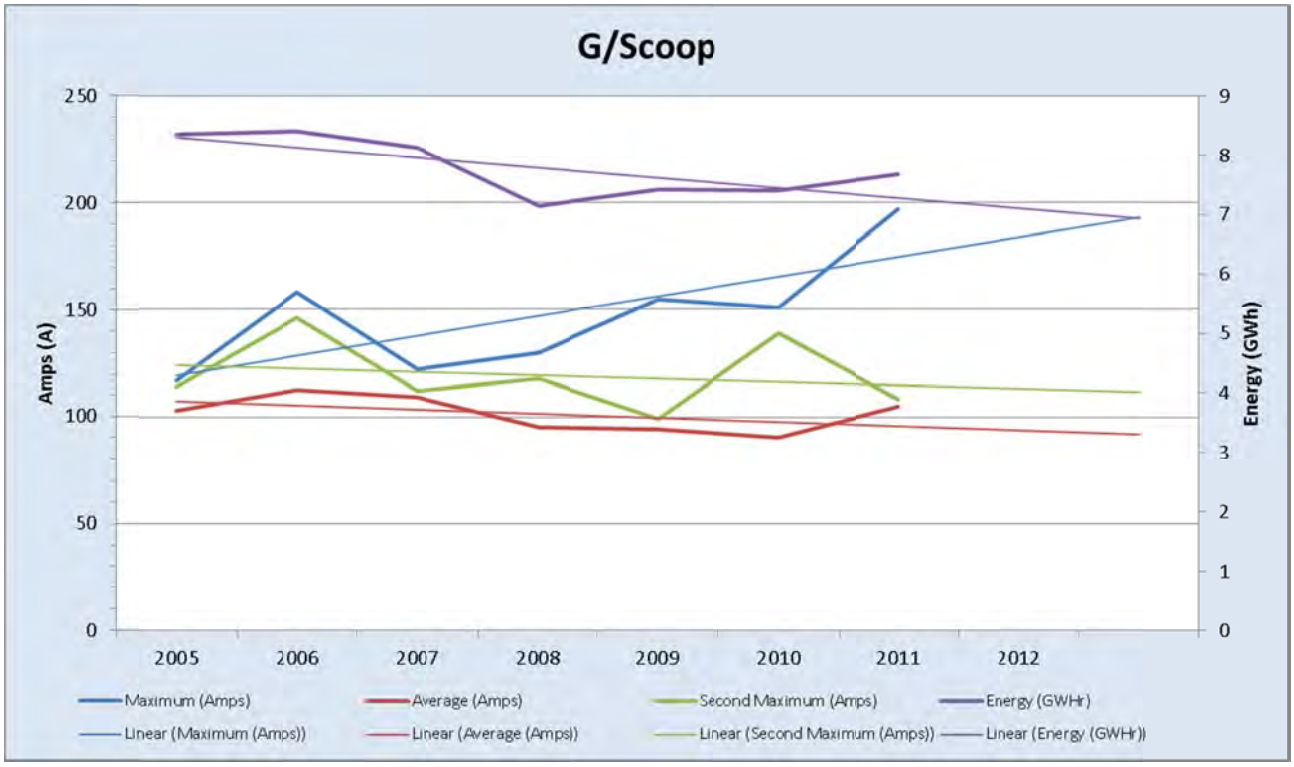
Load forecasts gives an estimate on the amount of electricity required in different parts of geographical area served by TLC.

TLC uses an internally developed spread sheet model to forecast the future energy demand on the network for the planning period of next 15 years. The spread sheet consists of historic data collected from SCADA loading figures. The data is graphed and a trend line used for the predicted growth or percentage growth per year. Adjustments are made to the percentage growth figure to allow for known system growth and feeder development projects. Adjustments are also made for spikes in the trend line that give unrealistic percentage growth factors. Table 5-3 indicates the factors considered when adjusting the percentage growth rate.

Feeder	Northern (Supplies Northern area of Taumarunui)	Gravel Scoop (Supplies South West area of Otorohanga)
GXP	**Ongarue**	**Hangatiki**
Class	Res/Rural/Lifestyle	Res/Rural/Industrial
Length (km)	130.22	109.9
Used to back-feed adjacent feeders	Yes	Yes
Installed kVA	7877	5320
Max Loading (Amps)	137	193
Approx. MVA	2.6	3.8
Trend:		
Max Increase (includes back-feeds)	0.125	0.035
Average Max Increase	-2.00%	-1.90%
Energy Increase	-9.7%	-2%
Previous year's Increase	0.7%	0.2%
2010/11 Increase setting	0.1%	0.2%
Proposed Generation	No	No
Proposed Modular Substations	Yes	Yes
Other e.g. Pivotal industrial loads	No	No

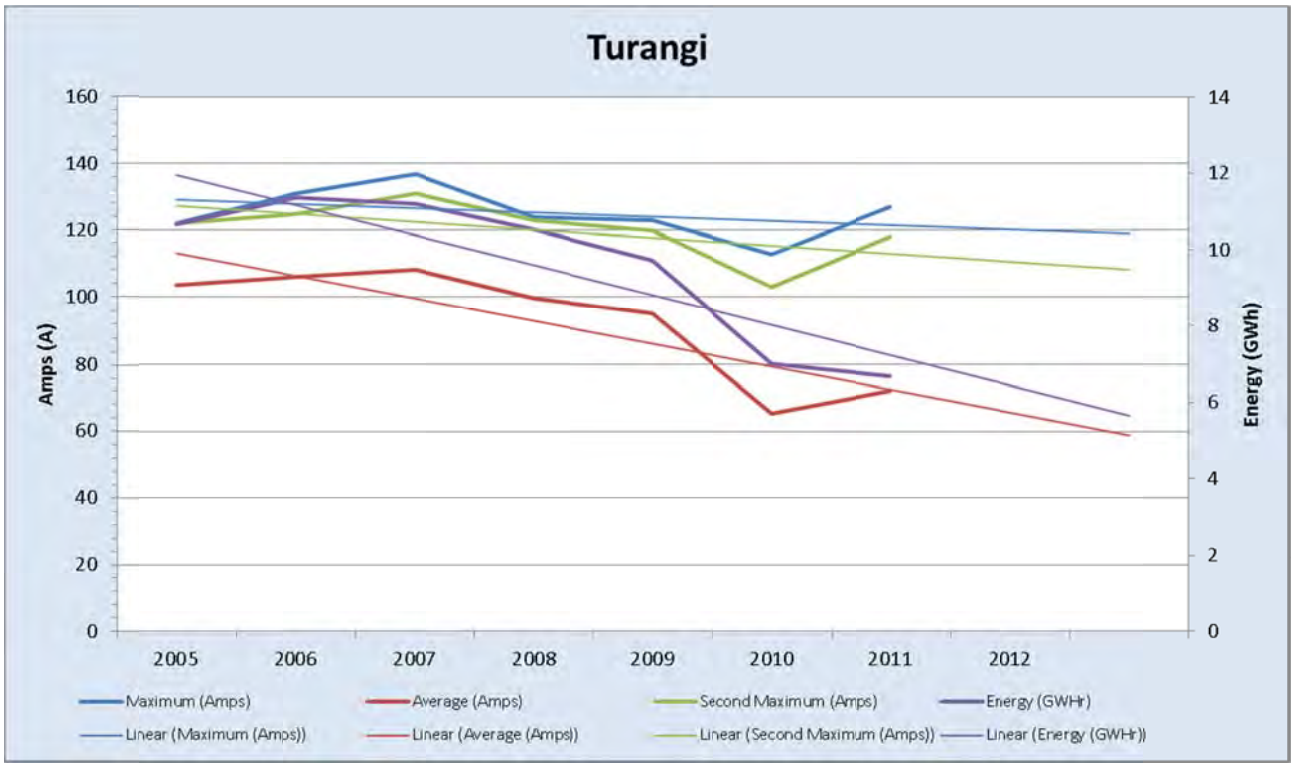
TABLE 5-3: FACTORS CONSIDERED WHEN ADJUSTING % LOAD GROWTH FOR FEEDERS

Graphs 5-1 and 5-2 illustrate a sample of data collected and the graphs used to ascertain the straight line growth trends.



GRAPH 5-1: FEEDER DATA GROWTH TRENDS - LOAD, AMPS AND ENERGY CONSUMPTION

(Gravel Scoop feeder from Te Waireka Zone Substation Otorohanga)



GRAPH 5-2: FEEDER DATA GROWTH TRENDS - LOAD, AMPS AND ENERGY CONSUMPTION

(Turangi Town Feeder)

With reference to the data shown in Graph 5-1, Gravel Scoop Feeder, that is supplied from Hangatiki grid exit point, indicates the trend is an increase in energy consumption, as well as a sharp increase in the maximum current transported at one time. This may be due to back-feeding support for adjoining feeders during maintenance or fault conditions throughout the year. The Network Planner needs to factor this increase into the 15 year plan to ensure that back-feeding is still possible to reduce SAIDI and SAIFI minutes

Graph 5-2 indicates that the Turangi Town Feeder, that is supplied from the Tokaanu grid exit point, has a trend line indicates a large decrease in energy consumption. (The thinking is that this large decrease is due to demand billing) The trend line also shows an increase in the maximum current transport at one time.

The information is then fed into a power flow analysis program, where load forecasting is programmed up to 15 years ahead. The voltage levels, expected current levels and the effects of power factor can all be modelled and planning upgrades can be programmed accordingly. The feeder loading data is broken down into high load, average load and low load.

When using the power flow program to analyse the data, typically the high load is used when considering worst case feeder restraints situations, the average load when planning shutdown back-feeds and the low load is used when considering worst case distributed generation applications.

TLC uses GIS Arc-Map for all topographical data. Data from Statistics NZ can be overlaid into TLC's mapping data to monitor population growth trends.

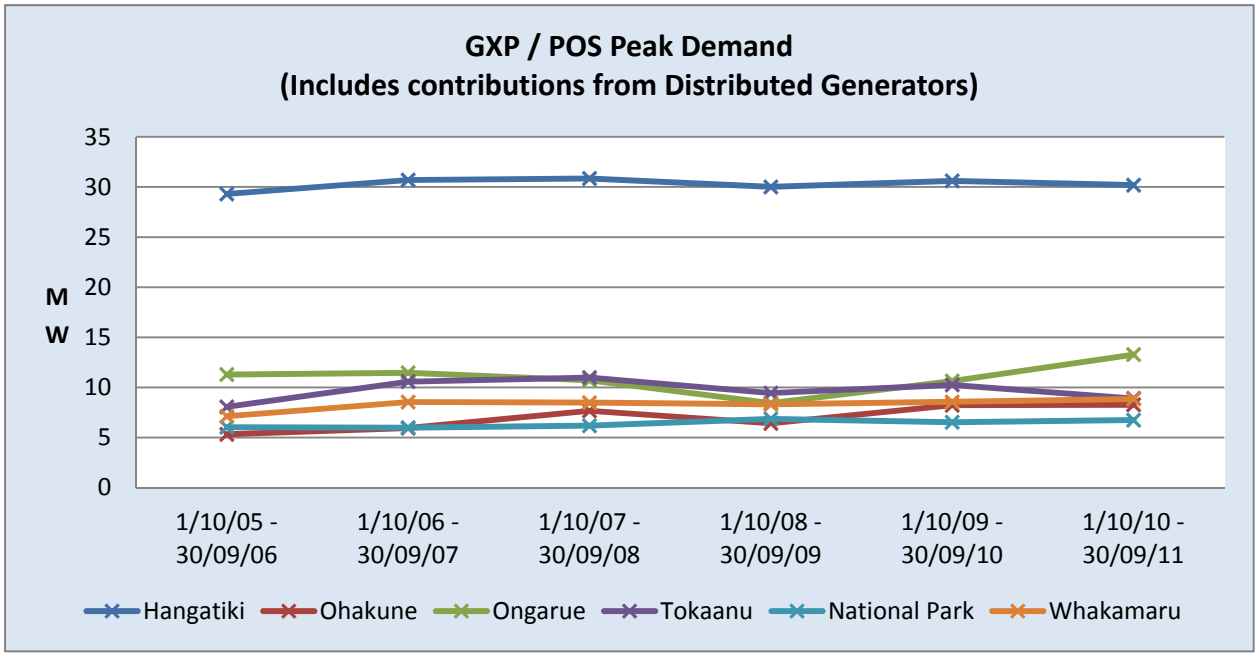
5.3.2.1 Typical factors considered when adjusting the straight line growth principle are:

5.3.2.1.1 Energy Transported and Peak Demands

Refer to Graph 5-3 "Instantaneous Peak demand trends from 2005/06 to 2010/11" and Table 5-4 "Peak Demand in MW". These figures are based on the most recent winter so are taken from October to September.

The overall base data used for load forecasts include the energy transported and peak demand figures as listed in Section 3 Tables 3-1 and Table 3-2 of this AMP plan. (These figures are based on TLC's financial year from April to March and include the winter before last). If the figures from the Tables in Section 3 are averaged over five years, the energy units transported have been increasing at 1.61 % and the system peaks at 1.84 % per annum.

Demand based billing was introduced in 2007 and, possibly as a consequence of this, the demand for the 2008/09 year actually reduced while the energy transported remained approximately constant. Demands do fluctuate from year to year and Graph 5-3 indicates the trends over the last 5 years. Table 5-4 lists the figures illustrated in Graph 5-3. The table lists the supply points with the actual and average changes over the last 5 years. These are the instantaneous peaks in MW.



GRAPH 5-3: INSTANTANEOUS PEAK DEMAND TRENDS FROM 2005/06 TO 2010/11

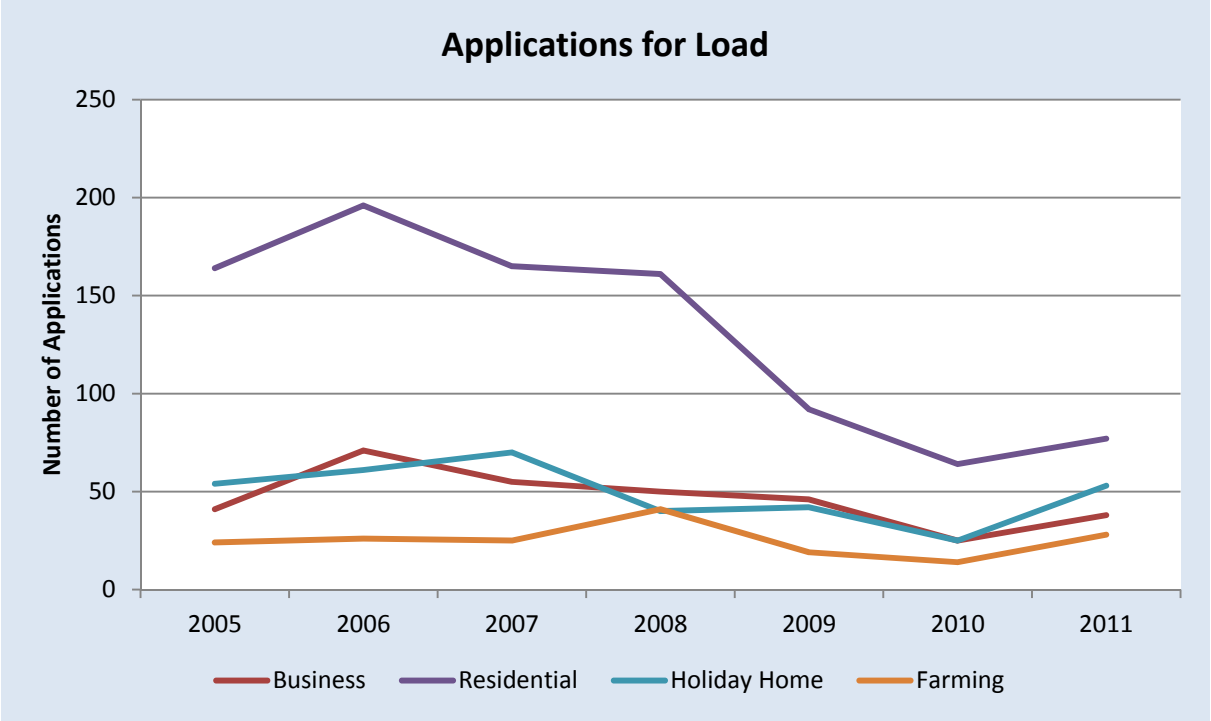
GXP / Point of Supply	1/10/05 - 30/09/06	1/10/06 - 30/09/07	1/10/07 - 30/09/08	1/10/08 - 30/09/09	1/10/09 - 30/09/10	1/10/10 - 30/09/11	Average change
	MW	MW	MW	MW	MW	MW	% p.a.
Hangatiki	29.30	30.69	30.84	30.00	30.60	30.18	0.63
Ohakune	5.32	5.94	7.66	6.42	8.22	8.26	10.59
Ongarue	11.28	11.46	10.70	8.44	10.64	13.28	4.94
Tokaanu	8.06	10.58	10.98	9.44	10.24	8.90	3.28
National Park	6.03	5.98	6.18	6.86	6.52	6.74	2.39
Whakamaru	7.12	8.54	8.48	8.30	8.56	8.84	4.70

TABLE 5-4: PEAK DEMAND IN MW

(DEMAND FIGURES INCLUDE CONTRIBUTIONS FROM DISTRIBUTED GENERATORS)

5.3.2.1.2 Applications for Load

Graph 5-4 (Applications for Connecting Load onto TLC's Network) illustrates the trend in applications for load development. Residential housing, businesses and holiday homes have shown a great downturn over the previous 5 years, but in 2011 this trend as showing an increase in all sectors.



GRAPH 5-4: APPLICATIONS FOR CONNECTING LOAD ONTO TLC'S NETWORK.

Further information that gives the Planning Engineer an indication of possible load growth changes include:

- Records of applications regarding electricity availability and subdivision information as required by councils for resource consent provision.
- Building consents.
- Pillar box records.
- Feeder and GXP loadings.

5.3.2.1.3 Effect of Embedded Generation

There are eight existing distributed generators of significance (about 28 machines) connected to the TLC network.

The factors taken into account when modelling generation includes:

- Output during periods of peak network loads.
- Output during periods of minimum network loads.
- Output during typical summer and winter network loadings.
- Expected operating power factors during the above periods.

5.3.2.1.4 Effect of Construction of a New Zone Substation

Forward estimates have included the effects of additional modular zone substations and the resulting feeder breakup. For example: with reference to Table 5-6 in Section 5.3.3.4. "Northern Area Distribution Feeders Load Forecasts" the forecast feeder loading, in year 20-21 includes a modular substation that is proposed for Ranganui Road. This will reduce load on the Pureora Feeder. These changes are built into the modelling of the network.

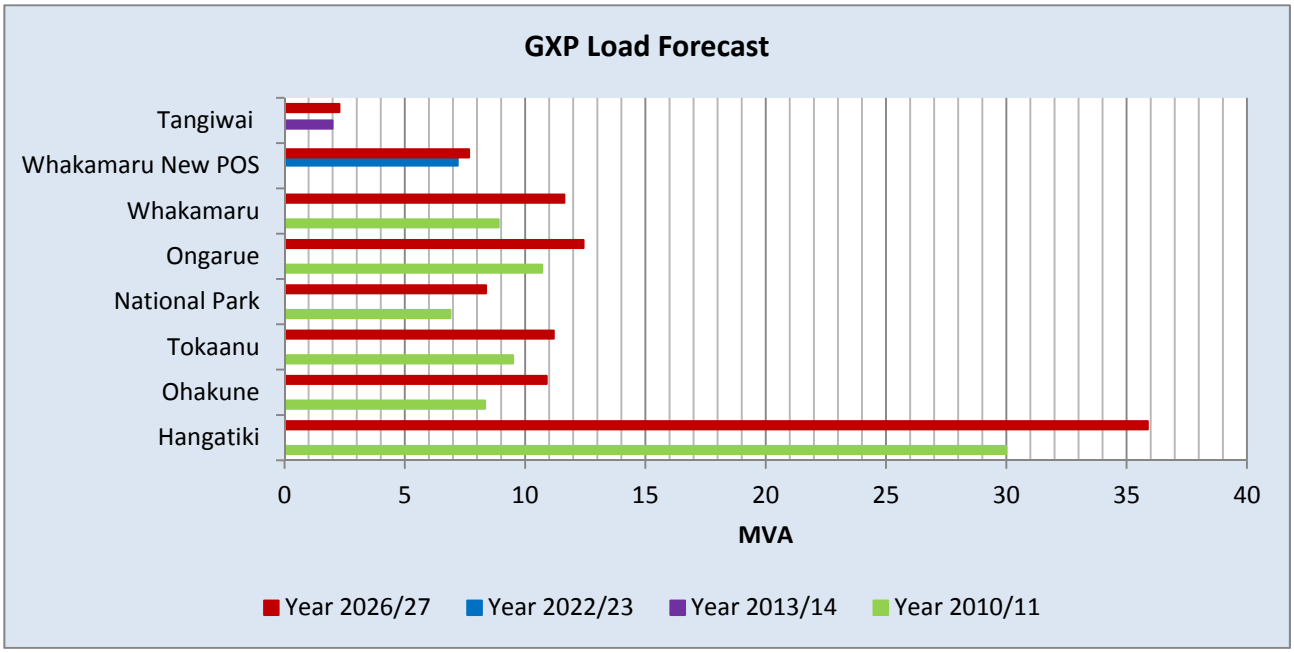
5.3.3 Load Forecasting Broken down to Feeder Level over the 15 Year Planning Period

Detailed below are the specific load forecasts down to 11 kV feeder level and the associated reasons for the forecast, based on the methodologies and data included in Section 5.3 that details how TLC prioritises projects.

5.3.3.1 Supply Area Projected Demands

Refer to Graph 5-5 "Projected Supply Point Current & 15 Year Forecasted Loads"

Graph 5-5 illustrates the forecast growth rate for the planning period in each supply area inclusive of existing generation. The grid exit loads are less than the system loads for the areas that are inclusive of distributed generation. The graph is in MVA and shows the 2011/12 maximum load against the forecast load for years 2026/27. The figures take into account the poor power factor at grid exits due to the effects of distributed generation.



GRAPH 5-5: PROJECTED SUPPLY POINT CURRENT & 15 YEAR FORECASTED LOADS

Uncertainties associated with these projections:

- Hangatiki has seen a slump in growth over the past couple of years; the figures assume that there will be continuing development of farming and primary products processors and this trend will reverse.
- If the effects of demand billing and the demand side management initiatives encourage constrained demand growth then further "head room" will be achieved at Hangatiki. The need for a new investment contract for a supply point transformer upgrade will be able to be further delayed. Distributed generation could also have a significant impact if the west coast wind farms come on line.
- Ohakune estimates assume no stepped changes to ski fields or holiday home developments. The present grid exit transformer has reached 95% of its capacity. It is assumed that a supply is brought out of Tangiwai to reduce this constraint in 2012/13.
- Tokaanu estimates assume continued but slow development in Turangi area. A prison expansion or other development associated with recreational activities will change this.
- There is adequate capacity at the Tokaanu supply point to provide for further growth unless there is an exceptional amount of development. (See network description section for details on this capacity.)
- National Park estimates assume no stepped growth on the Whakapapa ski field or National Park Village. The World Heritage Park plan controls growth in this area and as a consequence it is highly unlikely there will be stepped changes.
- Ongarue estimates assume a small amount of growth in the Taumarunui area associated with dairy farming and lifestyle development surrounding the township. Continued increase in heat pump loads could affect these assumptions.
- A new 10MVA substation (Point of Supply) is proposed for Whakamaru in year 2022/23 to accommodate increasing growth of local dairy farming and irrigation pumps along Waikato River. Furthermore, Atiamuri Zone transformer is on the verge of constraining at the end of the planning period (refer Table 5-5: Sub Transmission) and a new substation will remove this constraint.

5.3.3.2 33 kV Lines Projected Demands

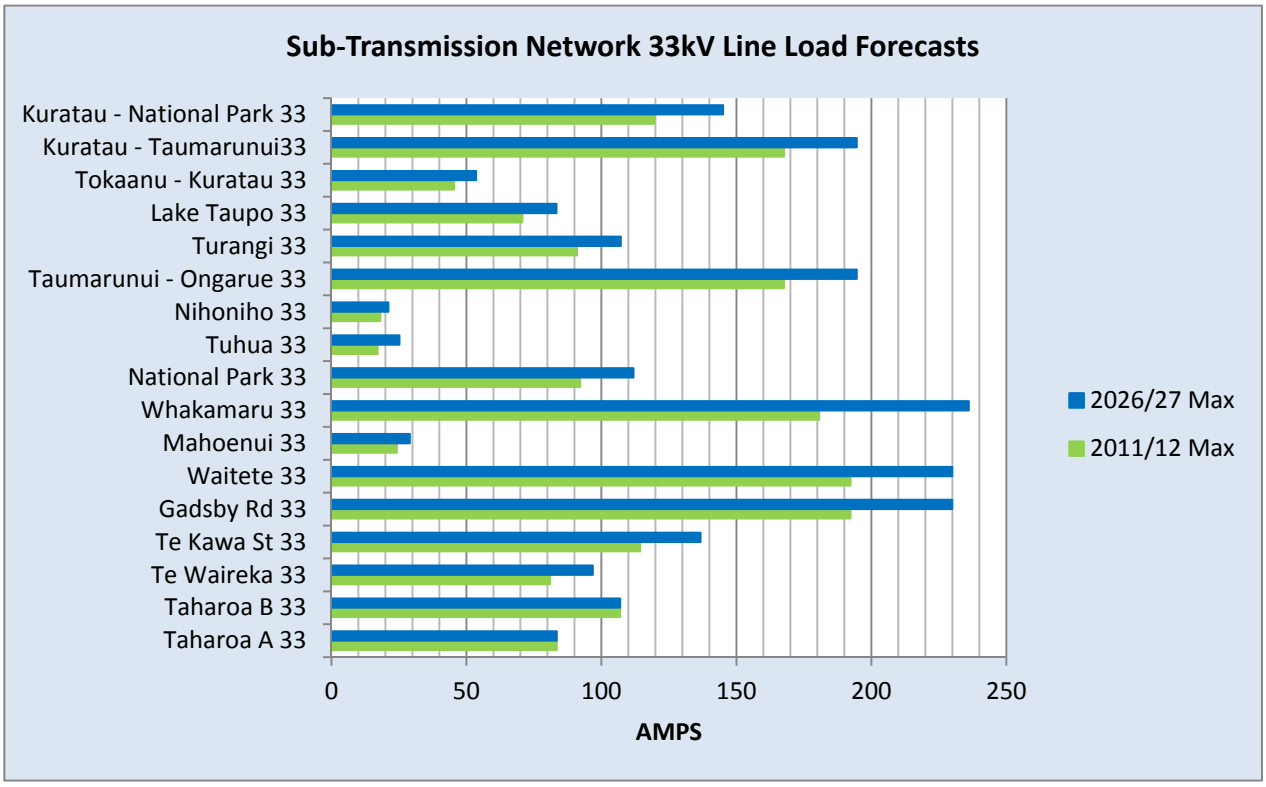
Graph 5-6 illustrates the load for 2011/12 year and the forecast loadings for the 15 year planning period for each of TLC's sub-transmission lines.

Where 33 kV data is not available; the estimates are back calculated based on 11 kV recordings. Some assumptions have to be made including:

- Lines that operate in parallel share the load evenly.
- It is assumed that distributed generation is not available. (Worst case)
- Substations connected to a particular circuit have concurrent peaks.

The currents on the Taharoa lines do not include the effects of the wind farm distributed generation effects. If these applications go ahead, the Taharoa A line will have to be converted to 110 kV.

It has been assumed the existing network configuration will be maintained in the Taumarunui and Kuratau areas and that the Kuratau generators will fund more of the cost of the Manunui to Kuratau 33 kV line. (This will make it uneconomic to take supply out of Transpower Taumarunui)



GRAPH 5-6 33 KV LINE FORECASTS

5.3.3.3 Zone Substation Projected Demands

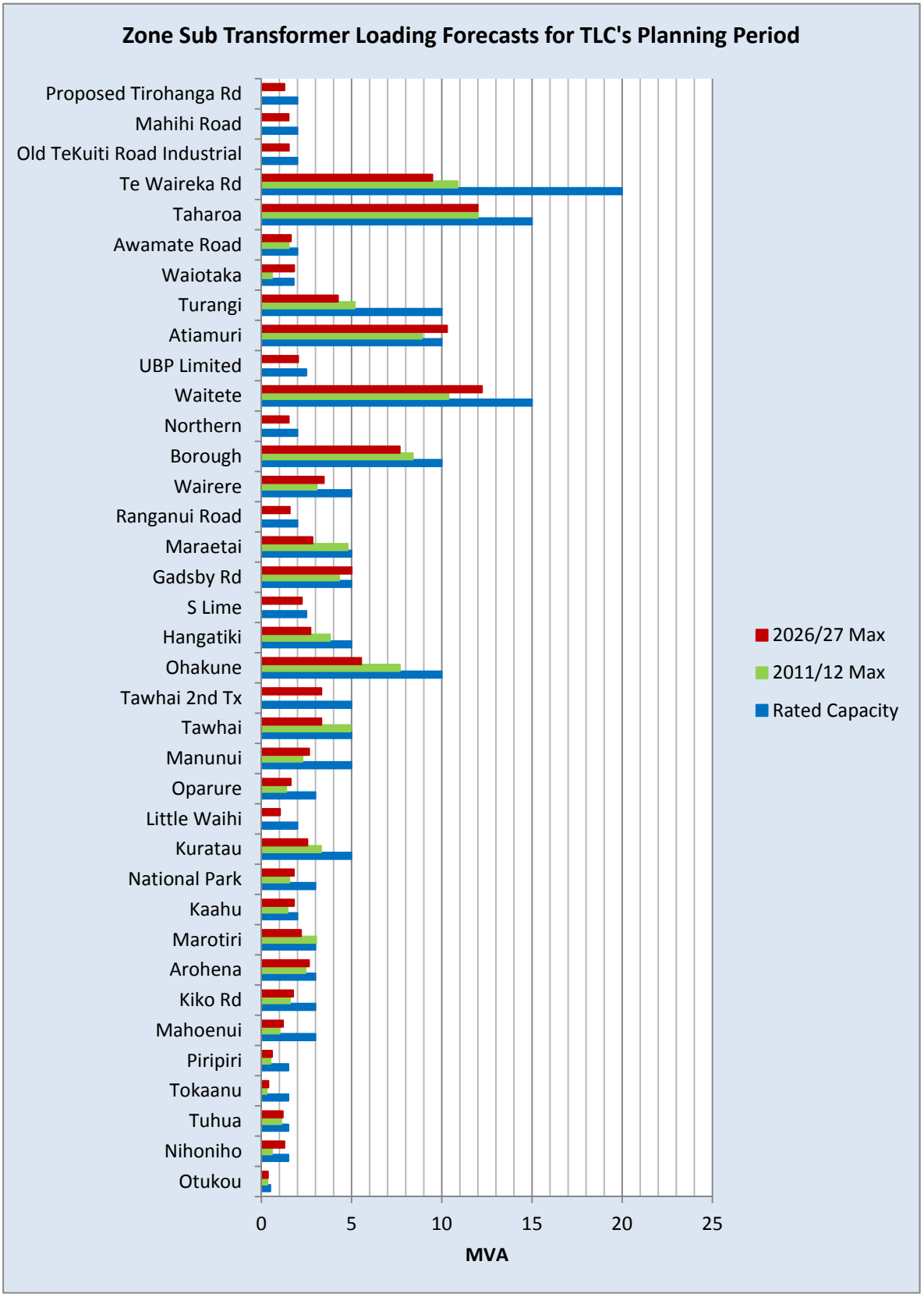
These forecasts assume the adoption of the development plan included in later sections of the plan and the upstream projects described in earlier sections taking place.

Specific assumptions include:

- Tatu mine opening in 2021, hence the increased loading at Nihoniho zone substation. If this does not eventuate there will be little impact on sub transmission assets. Due to many years of dry stock farm rationalisation there is capacity in this area.
- Load at Whakapapa slowly developing such that an additional transformer is needed at Tawhai in 2019/20. If the development of the ski field does not eventuate there will be little impact other than an additional transformer will not be required. (Existing transformer is proposed to be run into overload due to low ambient temperatures when loading is greatest.)
- Establishment of a modular substation at Waihi to backup Kuratau and holiday home developments in 2021/22. It is expected that the Waihi distributed generation will be re-commissioned around this time. This will be needed to export Waihi generation and reduce the loading on the Kuratau transformer. If the Waihi generation is not re-commissioned (this is an abandoned site dating back to the 1920's) then it is likely that the project will still be needed due to holiday home development and increasing customer reliability expectations in the Kuratau area.
- It is assumed a substation will be needed in Ranginui Road about 2020/21 to service increasing development at the Crusader Meat Plant. (This will be needed to reduce loading on the Maraetai transformer, voltage drop on the Pureora feeder and conductor loadings.) There is a proposed hydro scheme in the area that is a small and run of the river scheme. The greatest demand is from the dairying in the area and from the meat processing plant whose peak time is through the lamb kill in the summer months. This is when the river is normally at its lowest and generation nil, therefore the zone substation will be required to boost the voltage whether or not the distribution generation project goes ahead. If the Crusader Meat Plant were to reduce in size and farm development in the area were to stop then the need for an additional modular substation would not be alleviated due to the cumulative increasing load on the Maraetai zone substation. It would however, be likely that the project would be delayed beyond the planning period as it presently exists.
- Lime processors in Te Kuiti/Otorohanga area opting for a modular substation in 2021/22 to improve plant reliability and increase capacity. If the Te Kuiti industrials choose not to expand and fund this project then the status quo would exist. The 11 kV feeders would be under pressure at times and this pressure would have to be alleviated by demand side initiatives such as power factor improvement.
- Continued lifestyle and residential development at the north end of Otorohanga resulting in the need for a 33 kV extension, and a substation to support the load, in the Maihiihi area. This is programmed for 2026/27 and is dependent on how quickly the lifestyle blocks are sold and built on. If this happens faster the project will need to be brought forward; if not the status quo configuration will continue. This will reduce the load supplied by Te Waireka zone substation.

- Industrial load creep at meat processors' plant in Te Kuiti requiring an additional container substation in 2017/18. This project will not be needed if plants close or reduce load. The timing is dependent on a combination of industrial load creep and demand side management (mainly power factor improvement) no longer being able to work together and maintain supply quality and security at a level acceptable to industrial customers. The status quo will likely remain until these criteria are triggered.
- An additional container sub is installed in the Mangarino Road area in 2021/22 to pick up industrial load creep associated with dairying and lime processing. This will reduce the load from Te Waireka zone substation. This project will not be needed if plants close or dairying load does not continue to expand. The timing is dependent on a combination of industrial and dairying load creep and demand side management (mainly power factor improvement) no longer being able to work together and maintain supply quality and security at a level acceptable to industrial customers, The status quo will likely remain until these criteria are triggered.
- An additional container sub north of Taumarunui in 2022/22. This is to minimise the flood risk at the Borough substation. The loading on the Northern feeder is expected to continue to increase as more heat pumps displace log fires in the northern part of Taumarunui. (This is being encouraged by the environmental agencies due to air pollution problems in the area.)
- Transformer replacement as proposed in the forward plan does occur.
- It is assumed that the Ohakune load will be supplemented by some additional supply out of Tangiwai.

Graph 5-7 "11 kV Zone Transformer Loading Forecasts" illustrate the zone substation transformer load of 2011/12 year against the 2026/27 year at the end of the planning cycle. Table 5-5 shows the figures used for the forecast and pink highlights are when zone transformers are forecast to overload. The green cells indicate when a development project is programmed and the anticipated changes in loading.



GRAPH 5-7: 11 KV ZONE TRANSFORMER LOADING FORECASTS

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31														
			2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Otukou	0.5	1 x 0.5	0.34	0.35	0.35	0.35	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.37	0.37
Nihoniho	1.5	1 x 1.5	0.60	0.61	0.62	0.62	0.63	0.64	0.65	0.66	1.17	1.19	1.21	1.23	1.25	1.26	1.28
Tuhua	1.5	1 x 1.5	1.11	1.12	1.12	1.13	1.13	1.14	1.14	1.15	1.16	1.16	1.17	1.17	1.18	1.19	1.19
Tokaanu	1.5	1 x 1.5	0.30	0.31	0.31	0.32	0.33	0.33	0.34	0.35	0.35	0.36	0.37	0.38	0.38	0.39	0.40
Piripiri	1.5	1 x 1.5	0.51	0.52	0.52	0.53	0.53	0.54	0.55	0.55	0.56	0.56	0.57	0.58	0.58	0.59	0.60
Mahoenui	3	1 x 3.0	1.03	1.04	1.06	1.07	1.08	1.09	1.10	1.11	1.13	1.14	1.15	1.16	1.18	1.19	1.20
Kiko Rd	3	1 x 3.0	1.60	1.61	1.62	1.64	1.65	1.66	1.67	1.68	1.69	1.71	1.72	1.73	1.74	1.75	1.77
Arohena	3	1 x 3.0	2.46	2.48	2.49	2.50	2.51	2.53	2.54	2.55	2.56	2.58	2.59	2.60	2.62	2.63	2.64
Marotiri	3	1 x 3.0	3.08	1.91	1.93	1.95	1.97	2.00	2.02	2.04	2.06	2.08	2.11	2.13	2.15	2.18	2.20
Kaahu	2	1 x 2.0	1.47	1.50	1.52	1.54	1.56	1.59	1.61	1.64	1.66	1.68	1.71	1.74	1.76	1.79	1.81
National Park	3	1 x 3.0	1.57	1.59	1.60	1.62	1.63	1.65	1.67	1.68	1.70	1.72	1.74	1.75	1.77	1.79	1.81
Kuratau	5	1 x 3.0	3.33	3.35	3.37	3.38	3.40	3.42	3.43	3.45	3.47	3.49	2.50	2.52	2.53	2.54	2.55
Kuratau Backup	1.5	1 x1.5															
Little Waihi	2	1 x 2.0											1.00	1.01	1.02	1.03	1.04
Oparure	3	1 x 3.0	1.40	1.42	1.43	1.45	1.46	1.48	1.50	1.51	1.53	1.55	1.56	1.58	1.60	1.61	1.63
Manunui	5	1 x 5.0	2.31	2.33	2.35	2.38	2.40	2.42	2.45	2.47	2.50	2.52	2.55	2.57	2.60	2.62	2.65
Tawhai	5	1 x 5.0	5.05	5.15	5.25	5.35	5.46	5.57	2.84	2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33
	5	2 x 5.0 (2018)							2.84	2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33
Ohakune	10	1 x 10.0	7.78	4.68	4.74	4.80	4.86	4.93	4.99	5.06	5.12	5.19	5.26	5.32	5.39	5.46	5.54
Hangatiki	5	1 x 5.0	3.85	3.88	2.42	2.45	2.47	2.50	2.52	2.55	2.57	2.60	2.62	2.65	2.68	2.70	2.73
S Lime	2.5	1x 2.5			2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25
Gadsby Rd	5	1 x 5.0	4.36	4.40	4.44	4.49	4.53	4.58	4.62	4.67	4.72	4.76	4.81	4.86	4.91	4.96	5.01
Maraetai	5	1 x 5.0	4.84	4.89	3.94	3.97	4.01	4.05	4.09	4.14	2.68	2.70	2.73	2.76	2.79	2.81	2.84
Ranganui Road	2	1 x 2.0										1.50	1.52	1.53	1.55	1.56	1.58
Wairere	5	2 x 2.5	3.10	3.12	3.15	3.17	3.20	3.22	3.25	3.28	3.30	3.33	3.36	3.38	3.41	3.44	3.46
Borough	10	2 x 5.0	8.49	8.57	8.66	8.74	8.83	8.92	9.01	9.10	9.19	9.28	7.38	7.45	7.52	7.60	7.67
Northern	2	1 x 2.0												1.50	1.51	1.52	1.52
Waitete	15	3 x 5.0	10.50	10.61	10.73	10.85	10.97	11.09	11.21	11.33	11.46	11.58	11.71	11.84	11.97	12.10	12.23
UBP Limited	2.5	1 x 2.5							2.01	2.01	2.02	2.02	2.03	2.03	2.04	2.04	2.05
Atiamuri	10	1 x 10.0	9.00	9.09	9.18	9.27	9.36	9.46	9.55	9.65	9.74	9.84	9.94	10.04	10.14	10.24	10.34
Turangi	10	2 x 5.0	5.19	5.20	4.20	4.20	4.21	4.21	4.22	4.22	4.23	4.23	4.23	4.24	4.24	4.25	4.25
		One unit southern back up unit 2018 and then taken to Tawhai.															
Waiotaka	1.8	1 x 1.8	0.60	0.61	1.61	1.63	1.65	1.66	1.68	1.70	1.71	1.73	1.75	1.77	1.78	1.80	1.82
Awamate Road	2	1 x 2.0	1.53	1.54	1.55	1.55	1.56	1.57	1.58	1.58	1.59	1.60	1.61	1.62	1.62	1.63	1.64
Taharoa	15	3 x 5.0	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Te Waireka Rd	20	2 x 10.0	11.01	11.14	11.28	11.41	11.55	11.69	11.83	11.97	12.11	12.26	12.40	12.55	12.70	11.36	9.48
Old TeKuiti Road Industrial	2	1 x 2.0													1.50	1.52	1.53
Mahihi Road	2	1 x 2.0														1.50	1.52
Proposed Tirohanga Rd	2	1 x 2.0		1.20	1.21	1.21	1.22	1.22	1.23	1.24	1.24	1.25	1.26	1.26	1.27	1.27	1.28

Pink Boxes indicate an overloading on the transformers

Green Boxes Indicate a change in system conditions

TABLE 5-5: SUB-TRANSMISSION: ZONE SUBSTATION TRANSFORMER FORECAST LOADS

5.3.3.4 11 kV Distribution Feeder Projected Demands

The significant events that could affect distribution feeder forecasts include:

- The changes to the sub transmission network as described in earlier sections.
- Establishment of an additional 11 kV feeder out of a new substation to supply Maihiihi. This assumes continuing growth north of Otorohanga. If this does not take place the status quo would remain.
- The existing TLC network configuration will largely remain unchanged.
- Lime processors partially funding modular substation to create new 11 kV feeder in Old Te Kuiti Road. If this does not take place, the existing network will remain in place until there is some form of external trigger point. It is likely to be when industrial load growth coupled with demand side management (mostly power factor control) is no longer able to provide the quality and security of supply that customers require.
- Distributed generation projects that are not included in forecasts and likely to proceed in the planning period.
- A change in the historical growth patterns in the Taumarunui area. This could be brought about in the area caused by a surge in the uptake of heat pumps. If this takes place there will be pressure on sub transmission and distribution assets. A solution will be more modular substations and a point of supply out of the Taumarunui railway substation. If this were to occur the existing Ongarue grid supply point would likely be decommissioned.
- Continued growth in ski fields. Any sudden additional growth to be partly covered by demand side generation on ski fields. The cost of upgrading and supplying extra capacity to the ski fields will be substantial. As a result of this, it is likely that all the capacity in the present system will be used and then demand side generation used for peak control during the planning period.
- Continuing industrial load growth for areas around Te Kuiti. This is dependent on the demand for the primary products (meat, timber and lime) that the industrial processors produce.
- If expansion occurs, additional connections to the sub transmission network will be required. If not, the existing network configuration will remain.
- Continued growth in Ohakune area for current year. Few subdivisions and holiday homes transpired; however, TLC expects this to grow in coming years. Since the Ohakune transformer has reached its 95% capacity, much of the existing Tangiwai feeder will be supplied from a new POS at Transpower Tangiwai substation. This will avoid Ohakune Transformer overloading.
- Continued dairying and irrigation expansion in the Mangakino area.

Tables 5-6 “Northern Area Distribution Feeder Load Forecasts” and Table 5-7 “Southern Area Distribution Feeder Load Forecasts” show the forecast for the northern and southern areas of TLC’s Network. The green boxes indicate forecast developments that will change the feeder loadings if they go ahead.

The estimated forward loadings on distribution feeders are included in Tables 5-6 & Tables 5-7.

Northern Area Feeder Name	Feeder Number	Forecast MD's (A) for year ending March 31														
		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
McDonalds	110	192	194	197	199	202	205	207	210	213	216	218	221	224	227	230
McDonalds Lime Industrial	130	122	123	125	127	129	131	133	135	137	139	141	143	145	148	150
Gravel Scoop	109	108	109	109	109	109	110	110	110	110	110	111	111	111	23	23
Otorohanga	112	197	199	202	204	206	208	211	213	215	218	220	222	225	227	230
Maihiihi	111	218	222	225	228	232	235	239	242	246	250	253	257	261	265	181
Coast	125	27	27	27	27	28	28	28	29	29	29	30	30	30	31	31
Mokauiti	115	50	50	50	50	50	50	50	50	51	51	51	51	51	51	51
Mahoenui	113	44	44	44	44	44	44	44	44	44	44	45	45	45	45	45
Piopio	116	67	68	69	70	70	71	72	73	74	74	75	76	77	78	79
Te Mapara	117	41	41	42	42	43	43	44	44	45	45	46	46	47	47	48
Aria	114	28	29	29	29	29	30	30	30	30	31	31	31	31	32	32
Benneydale	103	280	283	286	289	293	216	218	221	223	225	228	230	233	236	238
Te Kuiti Town	105	54	55	55	56	57	57	58	58	59	60	60	61	62	62	63
Te Kuiti South	104	102	103	104	106	107	108	109	110	112	113	114	115	117	118	119
Rangitoto	106	143	144	145	146	147	148	149	150	151	152	153	154	155	157	158
Hangatiki East	102	172	174	176	177	179	181	183	185	187	110	111	112	114	115	116
Caves	101	54	55	55	56	57	57	58	58	59	60	60	61	62	62	63
Oparure	107	139	141	142	144	145	147	148	150	152	153	155	157	159	160	162
Waitomo	108	123	124	125	127	128	130	131	132	134	135	137	138	140	141	143
Wharepapa	122	115	117	119	121	122	124	126	128	130	132	134	136	138	140	142
Mangakino	118	43	43	44	44	45	45	46	46	47	47	48	48	49	49	50
Huirimu	121	32	32	32	32	32	32	32	32	32	32	32	32	32	32	33
Pureora	119	103	105	106	108	109	111	113	114	26	26	27	27	28	28	28
Whakamaru	120	101	101	101	102	102	102	102	102	102	102	102	102	102	103	43
Tirohanga	129	77	78	80	81	82	83	84	86	87	88	90	91	92	94	95
Mokai	123	137	87	88	90	91	92	94	95	97	98	99	101	102	104	106
Tihoi	124	49	50	50	51	51	52	52	53	54	54	55	55	56	57	57
Rural	126	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Mokau	128	54	55	55	56	57	57	58	58	59	60	60	61	62	62	63
Proposed Limestone industrial		0	0	0	0	0	0	0	0	0	104	105	105	106	106	107
Proposed Mangaoronga		0	0	0	0	0	0	0	0	0	0	0	0	0	0	90
Proposed Meat Processing Industrial		0	0	0	0	0	80	80	81	81	82	82	82	83	83	84
Proposed Mangaoronga Rd		0	0	0	0	0	0	0	0	0	0	0	0	0	90	91
Proposed Ranginui Road		0	0	0	0	0	0	0	0	100	102	103	105	106	108	109
Sandel Road		0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Proposed Tirohanga Rd			63	64	64	65	66	67	67	68	69	70	70	71		

Green Highlighting denotes a step change caused by a power system development

TABLE 5-6: NORTHERN AREA DISTRIBUTION FEEDER LOAD FORECASTS

Southern Area Feeder Name	Feeder Number	Forecast MD's (A) for year ending March 31														
		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Hakiaha	401	106	106	106	107	107	107	107	107	107	107	107	107	107	108	108
Northern	402	150	151	152	153	154	155	156	158	159	160	161	162	91	92	92
Western	403	75	76	77	79	80	81	82	83	85	86	87	89	90	91	93
Matapuna	404	144	146	149	151	153	155	158	160	162	165	167	170	172	175	178
Motuoapa	425	40	40	40	40	41	41	41	42	42	42	42	43	43	43	44
Oruatua	417	48	48	48	49	49	49	50	50	50	51	51	51	52	52	53
Hirangi	405	72	72	72	73	73	74	74	74	75	75	75	76	76	77	77
Turangi	423	127	127	128	128	128	128	128	128	128	128	129	129	129	129	129
Rangipo-Hautu	424	154	154	155	155	155	155	155	155	156	156	156	156	156	156	156
Waiotaka	427	32	32	32	33	33	33	34	34	35	35	35	36	36	37	37
Manunui	408	64	65	66	67	67	68	69	70	70	71	72	73	73	74	75
Southern	409	67	68	69	69	70	71	71	72	73	74	74	75	76	77	77
Ongarue	421	24	24	24	25	25	25	25	25	25	25	25	26	26	26	26
Tuhua	422	43	44	44	44	44	45	45	45	45	45	46	46	46	46	47
National Park	411	83	84	85	86	86	87	88	89	90	91	92	93	94	95	96
Raurimu	410	130	131	132	133	135	136	138	139	140	142	143	145	146	147	149
Otukou	418	18	18	18	18	19	19	19	19	19	19	19	19	19	19	19
Turoa	415	224	227	230	234	237	241	244	248	252	256	259	263	267	271	275
Tangiwai	416	121	64	65	65	66	67	68	68	69	70	71	71	72	73	74
Ohakune	414	170	137	138	140	141	143	144	146	147	149	151	152	154	156	157
Waihaha	426	60	60	60	60	61	61	61	62	62	62	63	63	63	64	64
Kuratau	406	150	151	152	153	154	154	155	156	157	109	110	110	111	112	112
Chateau	419	236	241	246	251	256	261	266	271	277	282	288	294	300	306	312
Tokaanu	420	14	14	14	14	15	15	15	16	16	16	16	17	17	17	18
Nihoniho	412	11	11	11	11	11	11	11	12	12	12	12	12	12	12	12
Ohura	413	25	25	26	26	26	26	26	26	26	26	27	27	27	27	27
Proposed Okahukaru		0	0	0	0	0	0	0	0	0	0	0	0	75	76	77
Proposed Little Waihi		0	0	0	0	0	0	0	0	0	50	51	51	52	52	53
Proposed Pulp Mill		0	60	61	61	62	63	63	64	65	65	66	67	68	68	69

Green Highlighting denotes a step change caused by a power system development

TABLE 5-7: SOUTHERN AREA DISTRIBUTION FEEDER LOAD FORECASTS

5.3.4 The Impact of Uncertain but Substantial Individual Projects on Load Forecasts

5.3.4.1 Wind Farm Projects

There are two large wind farm projects for which TLC has applications to connect to the network. The impact of these two projects going ahead will mean that one of the two existing 33 kV lines to Taharoa will need to be converted to 110 kV to transport the energy produced into the national grid.

The load for the Taharoa iron sands operation will consume some of the generation produced in the area;, therefore the importance on the existing lines for that particular industry will change.

The effects of the generation have not been included in the forecasts as the purpose and configuration of the network will change considerably to accommodate the generation. The modular nature of the upgrades if the sites do go ahead at the full capacity will have minimal impact in planning decisions for the remainder of the network.

5.3.4.2 Hydro Generation

Distributed generation (as discussed later in this section) has a dynamic effect on the network and there is a lot of uncertainty as to where and when developments will take place. As a consequence it is not practical to factor into future load predictions all possible effects. (There are many future potential distributed generation sites and where and when these will be consented and developed is uncertain.)

TLC at the time of writing has five applications but these projects are still uncertain as to when they will proceed.

The Plan includes a voltage regulator for the Gadsby – Wairere 33 kV line to pull the voltage down if a distributed generator does connect. This project is dependent on that development.

The Plan also includes a modular substation for the Ranganui Road area; if the proposed distributed generation does go ahead that this may defer this development project. This decision would depend on the generator's output and seasonal variability.

5.3.4.3 Industrial Site Expansions

TLC has a number of industrial sites that have approached TLC with upgrade and expansion plans. For those sites near a 33 kV line a TLC has programmed into the forecasts a modular substation that will allow the industrials the capacity to expand.

These include:

- A lime works where a modular substation will reduce the demand on Hangatiki East feeder and the transformer at the Hangatiki zone substation
- A meat works where a modular substation will reduce the demand on Benneydale feeder and the transformer at the Waitete zone substation.
- A second meat works where a modular substation will reduce the demand on Pureora feeder and the transformer at the Maraetai zone substation

If these industrial developments do not occur the modular substations proposed for the industrial site will be removed from the plan.

5.3.4.4 Dairy Farming & Irrigation

A large irrigation project in the Whakamaru area has been proposed and TLC has included it in this year's Plan. There is a possibility that there may be a ripple effect once farmers see the benefits of this project.

TLC has two modular substation planned for rural areas where irrigation may occur. If this development does not occur and the load growth in the area is stable with no capacity constraints, the proposed modular substations will not be installed.

5.3.4.5 Effects of Electric Vehicles

It is recognised that the introduction of electric vehicles has the potential to have a significant effect on the TLC network. In the longer term it may be that the energy transported to charge these vehicles will increase as they become more main-stream.

The demand effects, if this were to occur, would likely be significant. If the vehicle batteries were set up to assist demand side management by supplying power in peak times and absorbing power in off peak times, there could be a decline in peak growth. Alternatively, if no demand side management is implemented, peak demand could increase rapidly. It is hoped that demand billing would strongly encourage the former option. If the batteries assist demand management by supplying power directly from their reserves, the network fault level within the system could rise.

The timing of these vehicles turning up and the extent of penetration into the rural TLC environment is unknown. There are several penetration timing scenarios prompted by various motoring experts. A common theme amongst them is that electric vehicles are more likely to be adopted in urban areas as opposed to rural. Many of these writers suggest that electric vehicle penetration into rural areas will take a long time to develop given the current technological status of the batteries.

For example, the most likely vehicles that will be suitable for rural use will have a combination of petrol/diesel and electric motors with some battery storage. Toyota is understood to be developing a version of their Prius vehicle with this technology that will only have a fully electric range of 30 km.

For the purposes of the 20112/13 plan, the effects of electric vehicle penetration on the network have not been included.

5.3.5 Impact of Distributed Generation on Forecasts

5.3.5.1 The Impact of Distributed Generation on Supply Area Projected Demand Forecasts

Refer to Graph 5-8 "Projected Supply Point Injections and Loads Showing the Effect of Proposed Distributed Generation" and Table 5-8 "Existing & Projected Supply Point Injections with Demand Side Management against the Possible Impact of Distributed Generation"

The graph details the impact of existing and planned distributed generation on forecast demands at supply points. Distributed generation has the potential to save the need for supply point transformer upgrades at Hangatiki. It will however complicate the grid exit power factor compliance with connection codes at these sites.

Hangatiki "In Injections", either coming on sooner or later are dependent on the construction of Taharoa wind farms. The plan has these projects programmed for years 18/19 to 19/20 but these dates are based on the time it has taken developers to get to the stages they are currently at. The actual investment amounts that will be required by TLC are also unknown until designs are finalised.

The need to upgrade the transformer at Atiamuri can be delayed if distributed generation is connected on the Pureora Feeder. This will alleviate the supply constraints when supply from Whakamaru is unavailable.

The distributed generation at Kuratau and Piriaka currently allows extended Transpower maintenance outages at Ongarue.

Graph 5-8 illustrates the effect of anticipated generation and the estimated dates that the proposed distributed generation may connect to TLC's Network.

Graph 5-8 together with Table 5-8 shows that if the proposed wind-farms connect to Hangatiki in years 18/19 with 16 MVA and years 19/20 with 40 MVA, then the generation will support TLC's expected load and the remainder will be exported through Hangatiki GXP. This table includes the anticipated effect of demand side management initiatives.

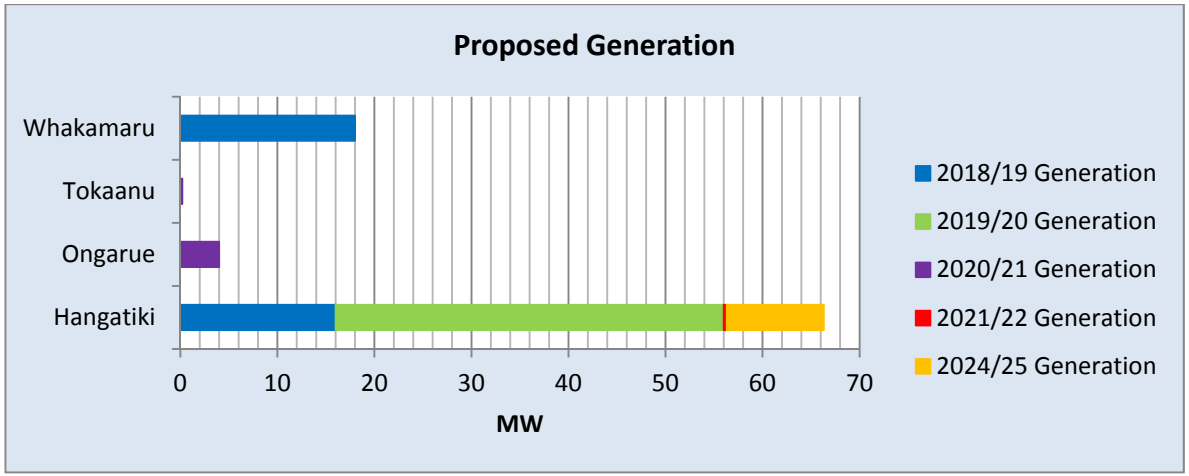
The hydro generation that is proposed for connection to Hangatiki GXP that will be transported through the Gadsby 33 kV will result in the need for regulators to pull the voltage down and the additional generation will constrain the capacity of the existing line. These are included in the plan.

The proposed generation connected to the Ongarue GXP will support the load and the excess will be exported.

The impact of the generation on the Pureora feeder will lighten the load on the Maraetai transformer and the generated capacity will be consumed within the feeder. The generation will also assist with voltage levels when Whakamaru supply point is out of service and supply is taken from Atiamuri.

There is no proposed generation that would connect to the grid through the National Park or Ohakune GXP's in this planning period.

The price of photovoltaic cells has reduced significantly in recent times to the point that demand side injections are now economic. The way this is going to impact on supply levels demand is unknown. The assumption at this time is that whilst energy quantities may reduce demand levels are unlikely to. This assumption is based on the observation that most peaks occur during winter evenings when no solar energy is available.



GRAPH 5-8: PROJECTED SUPPLY POINT INJECTIONS AND LOADS SHOWING THE EFFECT OF PROPOSED DISTRIBUTED GENERATION

Point of Supply Off Take verses Generation (MVA)																
		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Hangatiki	Generation	0.00	0.00	0.00	0.00	0.00	0.00	16.00	40.00	56.00	56.32	56.32	56.32	66.32	66.32	66.32
	Off Take	30.36	30.72	31.09	31.47	31.84	32.23	32.61	33.00	33.40	33.80	34.21	34.62	35.03	35.45	35.88
Ohakune	Off Take	8.49	8.64	8.80	8.96	9.12	9.28	9.45	9.62	9.79	9.97	10.15	10.33	10.52	10.71	10.90
Tangiwai	Off Take		2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25	2.28
Tokaanu	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Off Take	9.60	9.71	9.82	9.92	10.03	10.14	10.26	10.37	10.48	10.60	10.71	10.83	10.95	11.07	11.19
National Park	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Off Take	6.99	7.08	7.17	7.27	7.36	7.46	7.55	7.65	7.75	7.85	7.95	8.06	8.16	8.27	8.38
Ongarue	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
	Off Take	10.82	10.93	11.03	11.14	11.26	11.37	11.48	11.60	11.71	11.83	11.95	12.07	12.19	12.31	12.43
Whakamaru	Generation	0.00	0.00	0.00	0.00	0.00	0.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00
	Off Take	9.06	9.22	9.39	9.56	9.73	9.91	10.08	10.27	10.45	10.64	10.83	11.02	11.22	11.43	11.63
	Off Take											7.20	7.32	7.43	7.55	7.67
Mokai	Off Take	4.04	4.09	4.13	4.18	4.22	4.35	4.48	4.62	4.76	4.90	5.04	5.20	5.35	5.51	5.68

TABLE 5-8: EXISTING & PROJECTED SUPPLY POINT INJECTIONS WITH DEMAND SIDE MANAGEMENT AGAINST THE POSSIBLE IMPACT OF DISTRIBUTED GENERATION

5.3.5.2 The Impact of Distributed Generation on the Sub-transmission Network Forecasts

Refer to Table 5-9 "Forecast loads on sub-transmission lines"

Analysis of the network loading forecasts given the asset details, this table indicates that without the effects of distributed generation there will be loading and voltage issues on the following lines by the end of the planning periods:

- Gadsby 33 kV.
- Taumarunui Ongarue 33 kV.
- Kuratau /Taumarunui 33 kV.

The connection of wind farms at Taharoa will require the Taharoa A line to be converted to 110 kV. The distributed generation at Wairere and Mokauiti currently allows the Gadsby to Waitete 33 kV to be maintained without outages that will potentially affect large numbers of customers.

There have been several applications for consent to build further generation in this region.

33KV ESTIMATED LOADINGS (AMPS) BASED ON 11 KV CB SCADA																
	Feeder No	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Taharoa A 33	301	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Taharoa B 33	302	107	107	107	107	107	107	107	107	107	107	107	107	107	107	107
Te Waireka 33	303	82	83	84	85	86	87	88	89	90	91	92	93	95	96	97
Te Kawa St 33	304	116	117	119	120	121	123	124	126	127	129	130	132	134	135	137
Gadsby Rd 33	305	195	197	199	202	204	207	209	212	214	217	219	222	225	227	230
Waitete 33	306	195	197	199	202	204	207	209	212	214	217	219	222	225	227	230
Mahoenui 33	309	25	25	25	25	26	26	26	27	27	27	28	28	28	29	29
Whakamaru 33	310	184	187	191	194	198	201	205	208	212	216	220	224	228	232	236
National Park 33	601	93	95	96	97	98	100	101	102	104	105	106	108	109	110	112
Tuhua 33	602	17	18	18	18	18	18	18	19	19	24	24	24	25	25	25
Nihoniho 33	603	18	19	19	19	19	19	19	20	20	20	20	20	21	21	21
Taumarunui - Ongarue 33	604	169	171	173	174	176	178	180	182	183	185	187	189	191	193	195
Turangi 33	605	92	93	94	95	96	97	98	99	100	102	103	104	105	106	107
Lake Taupo 33	606	72	72	73	74	75	76	76	77	78	79	80	81	82	82	83
Tokaanu - Kuratau 33	607	46	47	47	48	48	49	49	50	50	51	51	52	52	53	54
Kuratau – Taumarunui 33	608	169	171	173	174	176	178	180	182	183	185	187	189	191	193	195
Kuratau - National Park 33	609	121	123	124	126	128	129	131	133	134	136	138	140	141	143	145

TABLE 5-9: FORECAST LOADS ON SUB-TRANSMISSION LINES

5.3.5.3 The Impact of Distributed Generation on Zone Substation Transformers Forecasts

Analysis of the loading forecasts in Table 5-5 "Sub-transmission: Zone Substation Transformer Forecast Loads" (Section 5.3.3.3) and tables in Section 3 giving asset details shows that without the effects of distributed generation there will be no significant changes to loading and voltage issues on zone substation transformers by the end of the planning period. Injection into the 11 kV beyond this period will ease the situation out into future planning periods.

Distributed generation connections will require the following zone substations to be upgraded during the planning period.

- Waihi : Additional 1.5 MVA
- Taharoa Interconnection : 40 MVA 33 kV to 110 kV transformer

These have been allowed for in forecasts. Auxiliary generation over peak periods on the ski fields has been assumed to delay the need to upgrade the Tawhai transformer as included in the Plan.

5.3.5.4 The Impact of Distributed Generation Distribution on Feeders on Forecasts

Analysis of the loading forecasts in Table 5-6 and Table 5-7 Northern and Southern Area Distribution Feeder Load Forecasts (Section 5.3.3.4) and tables in Section 3 giving asset details shows that without the effects of distributed generation there will be forecast loading issues on the following feeders:

- Benneydale – Distributed generation is currently being used to support voltage and reduce load current. If it did not exist, the 33 kV would have to be extended out of Maraetai sooner than the dates included in the plans. (Ranganui Road Modular substation would have to be established.)
- Pureora – Forecast proposed generation will support voltage.

5.3.6 Impact of Demand Management Initiatives on Forecasts

5.3.6.1 Effect of Auxiliary Generation on Peak Demand Reduction

5.3.6.1.1 The Ski Fields

Ruapehu Alpine Lifts (RAL) has installed a generator to bolster the supply during peak load periods such as snow making on a winter's night on its Turoa ski field. The company is also proposing another similar installation at Whakapapa.

The Turoa installation has only been used occasionally to reduce peaks due to the practical issues associated with getting enough fuel up to the ski field to the site. There are also clauses in the World Heritage Park Plan that will make running this plant for extended periods difficult. There is still an amount of capacity in the existing supply to both ski fields and demand side management savings via power factor improvements are potentially possible.

As a consequence of this the forward models have assumed expansion of loads on the ski fields until all of the existing capacity is used and then loads have been seen to not increase further. It has been assumed that by this time the current difficulties with the auxiliary generation will be overcome and it will be used to constrain load for the remainder of the planning period.

Auxiliary generation over peak periods on the ski fields has been assumed to delay the need to upgrade the Tawhai transformer.

5.3.6.1.2 Coastal Holiday Area

Mokau, during peak holiday times, with the anticipated growth is expected to constrain the existing lines midway through the planning period. This loading is seasonal and based around the holiday times.

Mobile distributed peak generation at holiday periods have been included in forecasts to support voltage.

Without this proposed auxiliary generation, the 33 kV would have to be advanced from Mahoenui during the early part in the planning period; at this stage, the expansion is programmed for year 14. Demand side management has given an additional 6-10 years' headroom.

5.3.6.2 Effect of Load Control on Peak Demand Reduction

TLC uses a load control system to reduce loading at peak periods. The load control targets are set, as best can be achieved with existing equipment, to align with Transpower's regional peaks and network constraints.

Customers have a ripple relay that controls hot water and other assigned loaded. Each ripple relay is assigned a channel and, TLC's SCADA system is programmed to automatically shed load based on the forecast loadings at peak times.

Load control through peak times delays the need to upgrade system capacity. This includes the Nihoniho transformer, which is forecast to reach full capacity near the end of the planning period and, without load shedding, this capacity would be reached earlier in the planning period. Comparisons of loads in the network analysis program indicate that a number of assets would be constrained at peak loading time much earlier in the planning period.

5.3.6.3 Effect of Peak Demand Billing on Peak Demand Reduction

In 2007 TLC introduced Demand Billing. TLC sets one billing rate for peak load over the year, based for most customers on the amount of energy consumed through the peak period. This is re-assessed each year after the peak demand period is over, at the end of September.

To get the full benefits of Demand Billing, customers need to have an advanced meter installed. This metering registers that a ripple signal is received and monitors the load consumed throughout the load control period. Customers also need to be aware of what appliances have high power consumption and if possible transfer these onto the control relays. TLC plans to roll out advanced meters to all customers over time; however, the initial focus will be on areas where there is no signal and Ohakune where there are

difficulties with the profiling methodologies due to the high proportion of holiday load. The roll out will be staged over time to ensure all difficulties with meters are identified and rectified.

The data from these meters are used to set the customers charges for the following year. The signal to customers is to reduce their consumption through the peak period, when TLC is shedding loads.

Initial work has produced calculations have shown that demand will have increased in the range of 0.2% to 1.3% greater than if financially driven demand side management had not been introduced. These percentages have been included in the growth rates and trend lines have been adjusted accordingly.

5.3.6.4 The Implications of Demand Side Management Initiatives

5.3.6.4.1 On Supply Points

5.3.6.4.1.1 General Discussion on Demand Side Management Effects on Substations

Refer to Table 5-10 "Forecast Grid Exit Loads Connected But Without Demand Side Management or Distributed Generation "and Graph 5-9 "Network Load Forecast with and without DSM"

Hangatiki - Forecasts as shown in Table 5-10 indicate that by the end of the planning period Hangatiki power off-take will be 43 MVA compared to an estimate of a predicted 35 MVA with demand side management; see Table 5-8 "Existing & Projected Supply Point Injections With Demand Side Management Against The Possible Impact Of Distributed Generation".

The principal implication of this is that the load will be reaching the combined full capacity of 47 MVA sooner than if demand side management had not been put in place. (See Section 3 for further details of ratings) Demand side management creates headroom. There is also a likely associated implication in that it will be difficult even at light load times to get the larger of the two transformers out for maintenance. With demand side management we may be able to delay the upgrade of the Hangatiki transformers. The upgrade cost will increase typical annual customer charges by substantial amounts.

Ohakune - At present when TLC's off take of about 8.3 MVA is added to Powerco's load, the grid transformers are fully loaded. Taking supply out of Tangiwai buys time, or up to 2 MVA of load. Calculations show that if a demand growth reduction of 0.5% were achieved from next year onwards, i.e. reducing growth from 1.8% to 1.3%, an additional four years would be gained in terms of the capacity of the Ohakune transformer.

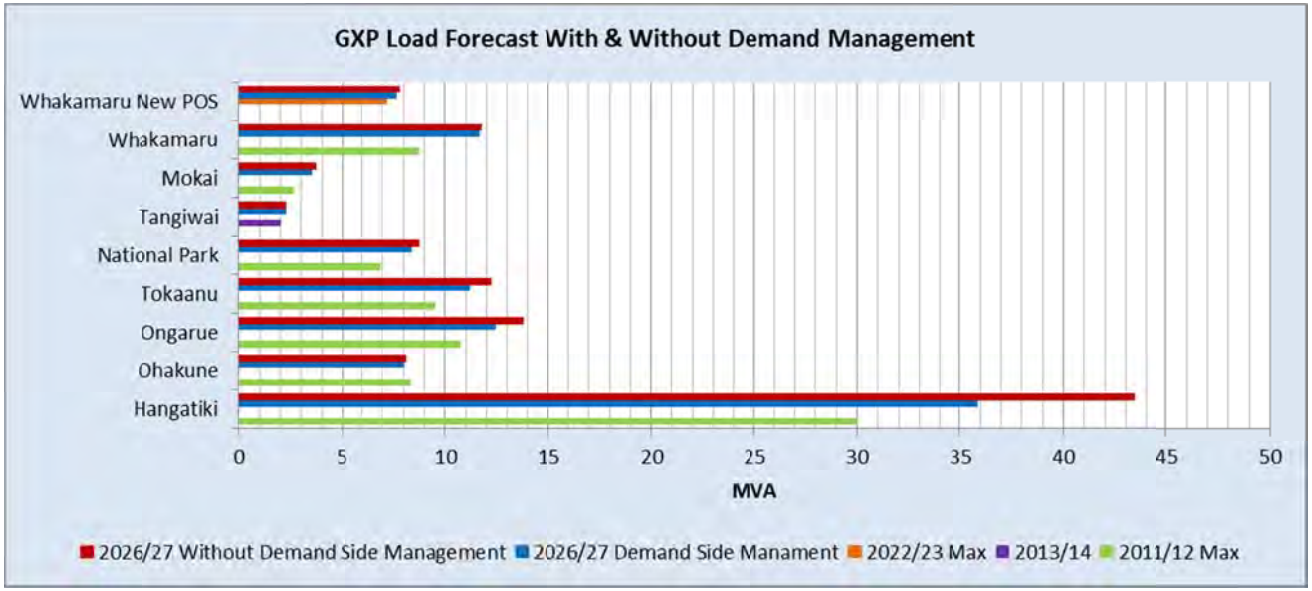
Tokaanu and Ongarue - It is predicted that if present growth in demand figures continue, then growth will be delayed by six and seven years respectively at these two sites. There are no supply point constraints on the planning horizon for either of these two sites.

National Park - Demand growth is being driven by the ski field and demand charging does not appear to have any significant effect in securing additional supply point headroom. Again, as with Ohakune, it is likely that without demand charging, growth would have been greater. It is known that the ski lodges for example have become more focused on demand control. (This however has been offset by expansions on the ski field).

Whakamaru/Atiamuri/Mokai – Without demand side management the Atiamuri supply transformer that backs this area up will be operating beyond acceptable loadings about one to two years sooner than without.

Forecast Grid Exit Loads without Demand Side Management in MVA																
		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Hangatiki	Off Take	30.75	31.52	32.31	33.11	33.94	34.79	35.66	36.55	37.47	38.40	39.36	40.35	41.36	42.39	43.45
Ohakune	Off Take	8.49	6.45	6.57	6.69	6.81	6.93	7.06	7.18	7.31	7.44	7.58	7.71	7.85	7.99	8.14
Tangiwai	Off Take		2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25	2.28
Tokaanu	Off Take	9.66	9.83	9.99	10.16	10.34	10.51	10.69	10.87	11.06	11.24	11.44	11.63	11.83	12.03	12.23
National Park	Off Take	7.29	7.39	7.48	7.58	7.68	7.78	7.88	7.98	8.09	8.19	8.30	8.41	8.52	8.63	8.74
Ongarue	Off Take	10.89	11.08	11.27	11.46	11.65	11.85	12.05	12.26	12.46	12.68	12.89	13.11	13.33	13.56	13.79
Whakamaru	Off Take	8.91	9.09	9.27	9.46	9.65	9.84	10.04	10.24	10.45	10.65	10.87	11.08	11.31	11.53	11.76
	Off Take											7.20	7.34	7.49	7.64	7.79
Mokai	Off Take	4.04	4.09	4.13	4.18	4.22	4.27	4.41	4.55	4.69	4.84	5.00	5.16	5.33	5.50	5.67

TABLE 5-10: FORECAST GRID EXIT LOADS CONNECTED BUT WITHOUT DEMAND SIDE MANAGEMENT OR DISTRIBUTED GENERATION



GRAPH 5-9: NETWORK LOAD FORECAST WITH AND WITHOUT DSM

5.3.6.4.1.2 The Effect of Maximum Demand Tariff's on Supply Point Loadings

The following are cost reductions that are handed on to customers as a result of maximum demand billing:

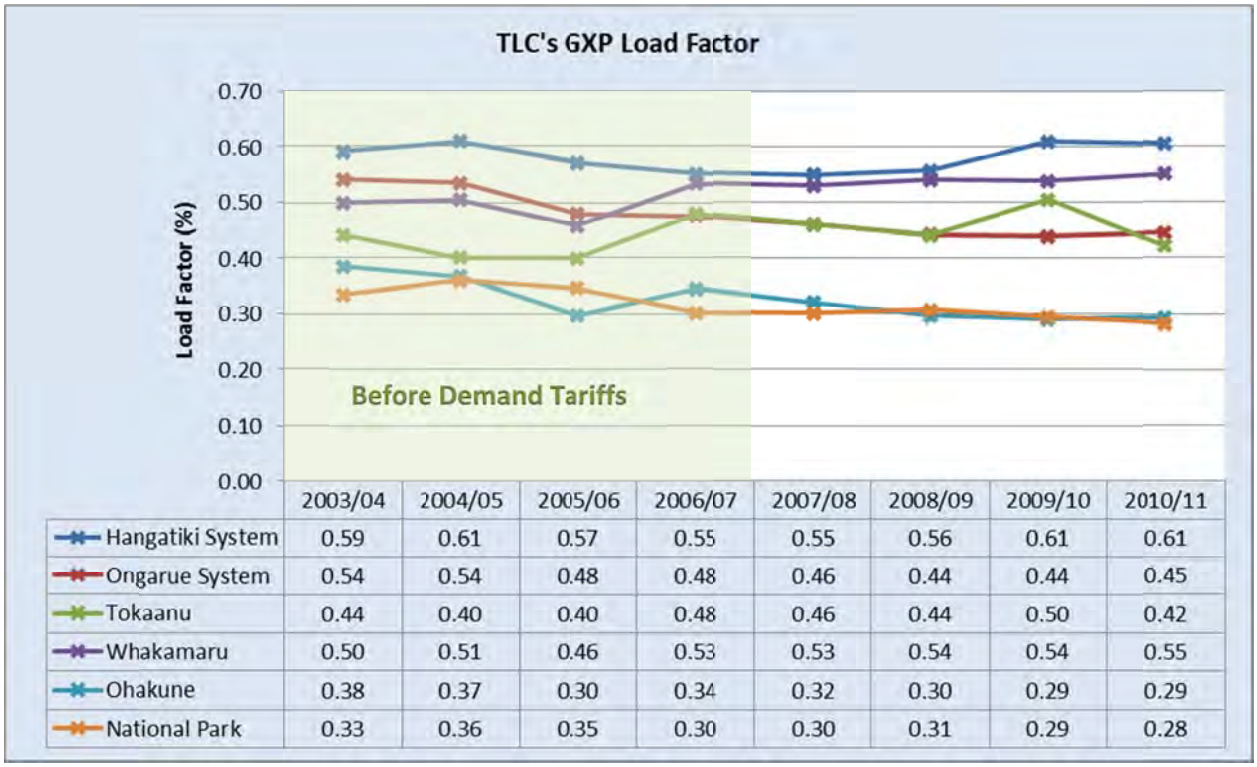
- A reduction in Transpower charges. TLC is able to reduce its loading during the nation's electricity peaks thus reducing the transmission charges imposed on it. In 2010 TLC system load was lower than in 2009 during a regional energy peak known as Regional Coincident Peak Demand (RCPD). As a result of this, TLC lowered its proportion of the nation's transmission charges.
- By reducing the peak loading on network assets this will increase life expectancy and reduce failures caused by electrical deterioration, which is aggravated by excess heating. Thereby assets replacement is pushed further out.
- Benefits may be gained through the deferral of capacity upgrades. These occur at all levels from transmission through to distribution. For example, TLC is outgrowing several National Grid assets that will cost several million to replace such as the Hangatiki 110/33kV transformer bank. These assets have not yet reached their life expectancy and could be replaced prematurely due to overloading. Their replacement will be expensive to both TLC and its customers.

Load factor is used to estimate the effects of TLC's maximum demand pricing options that were introduced in 2007.

The load factor is the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. It is a percentage derived using the following formula.

$$\text{Load Factor} = \frac{\text{Actual Energy Consumed}}{\text{Maximum Demand x Time in hours of period}}$$

See Graph 5-10 "Load Factor at each Supply Point for the TLC Network". Load Factor is on the Y axis. The figures used are from 1st October 2010 to the 30th September 2011 and includes the most recent winter. (This load factor figure varies slightly from the load factor figure in Section 4, which is based on the financial year 1st April 2010 to 31st March 2011.)

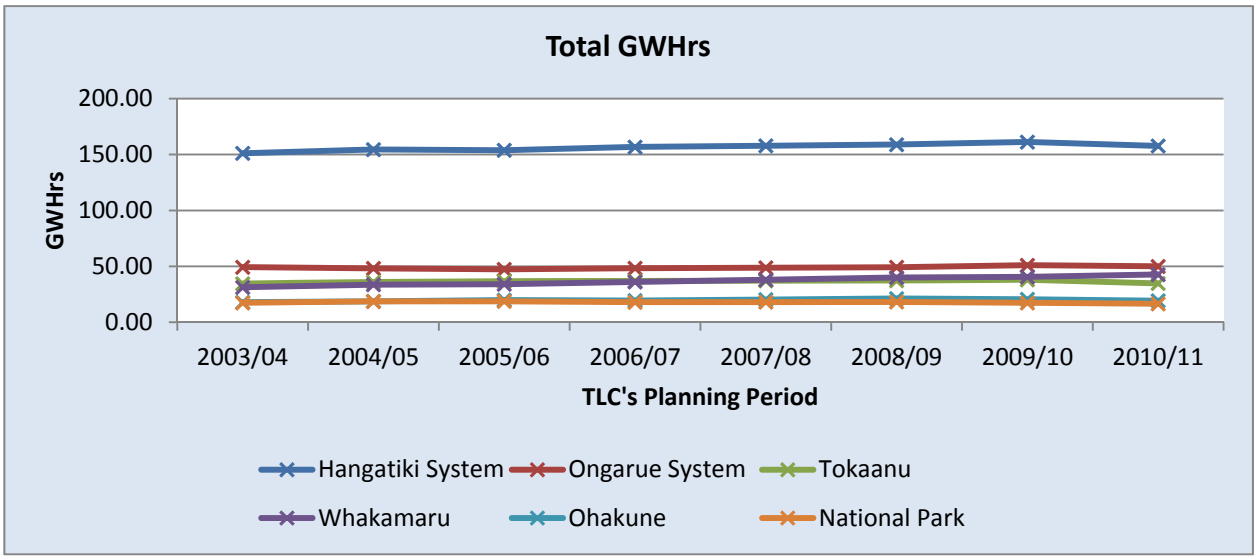


	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Hangatiki System	0.59	0.61	0.57	0.55	0.55	0.56	0.61	0.61
Ongarue System	0.54	0.54	0.48	0.48	0.46	0.44	0.44	0.45
Tokaanu	0.44	0.40	0.40	0.48	0.46	0.44	0.50	0.42
Whakamaru	0.50	0.51	0.46	0.53	0.53	0.54	0.54	0.55
Ohakune	0.38	0.37	0.30	0.34	0.32	0.30	0.29	0.29
National Park	0.33	0.36	0.35	0.30	0.30	0.31	0.29	0.28

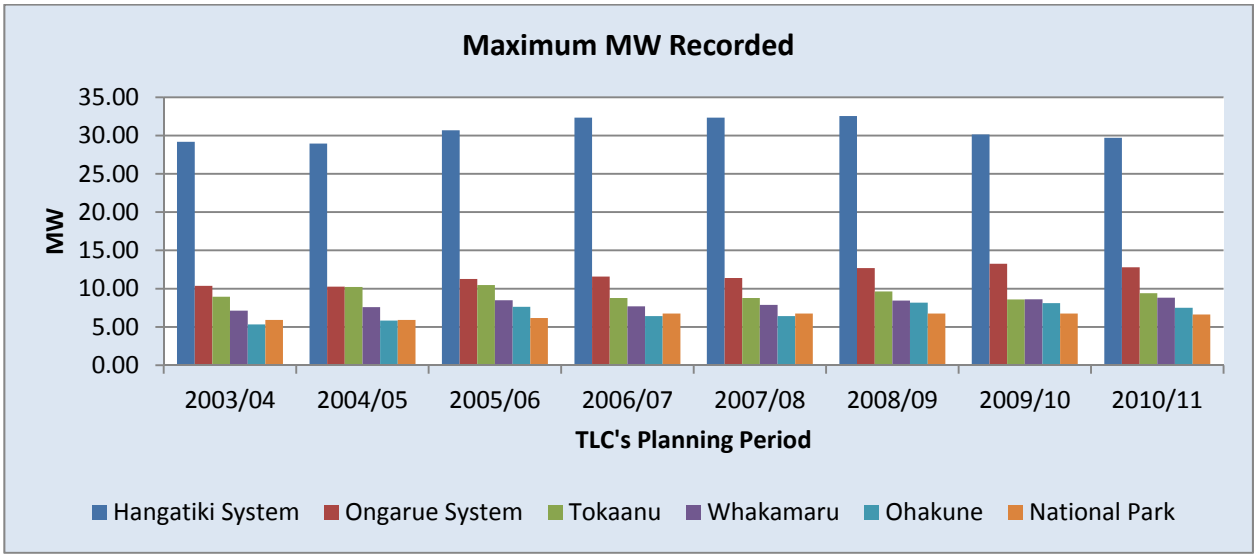
GRAPH 5-10: LOAD FACTOR AT EACH SUPPLY POINT FOR THE TLC NETWORK

A load factor that is improving indicates that there is better utilisation of the systems assets in moving peak demand from the peak times. Ideal is a load factor of 1.

Assumptions from this data need to be reconciled with the energy used as in Graph 5-11 "Energy Consumed per POS" and the demand as per Graph 5-12 "Demand per POS" as there may be factors such as people converting to gas and not using energy as compared to a shift in the peak demand load.



GRAPH 5-11: ENERGY CONSUMED PER POS



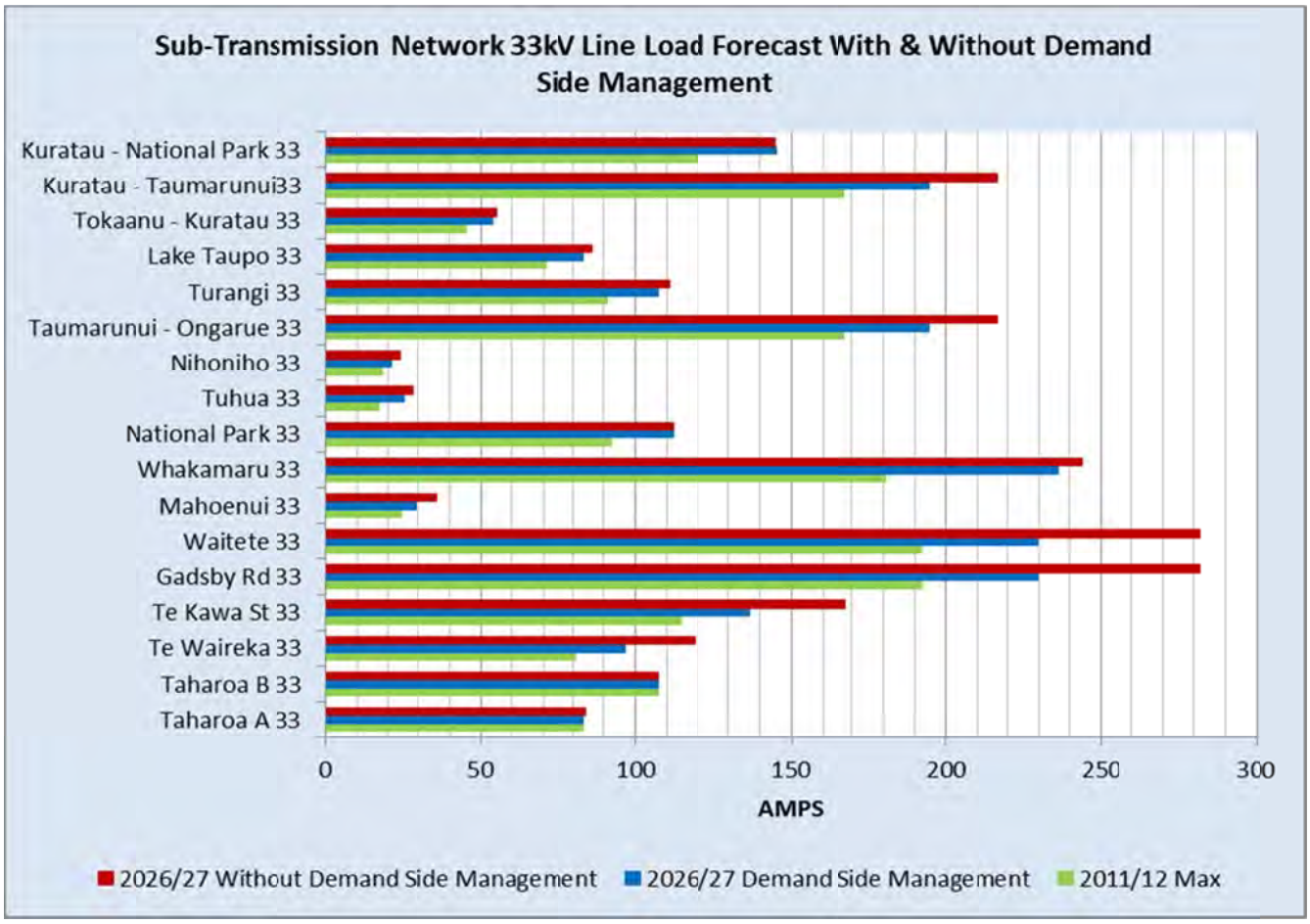
GRAPH 5-12: DEMAND PER POS

5.3.6.4.2 On 33 kV Lines

The network analysis program indicates that:

- Whakamaru 33 kV line, which is mink conductor, will be above the manufacturer's rating in 2017/18 without demand side management; it is estimated that demand side management will hold this upgrade for at least two years. Voltage regulation will provide some head room in the initial years.
- The voltage at Taumarunui will not be able to be maintained without demand side management initiatives beyond the end of the planning period; the models indicate operational limits will be tight but likely compliant at the end of the planning period.

Refer to Graph 5-13 "Sub Transmission Network Forecast with and without DSM".



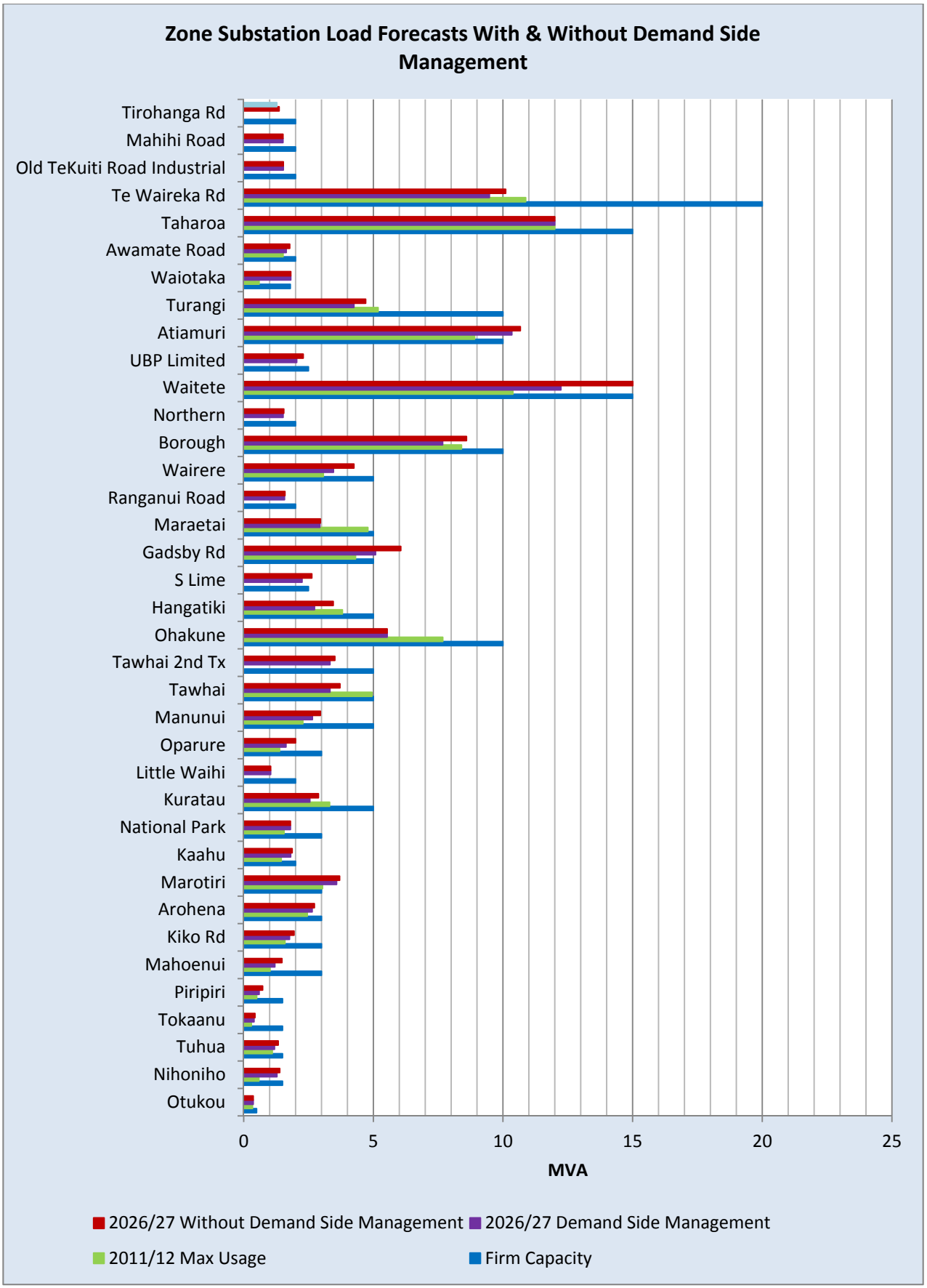
GRAPH 5-13: SUB TRANSMISSION NETWORK FORECAST WITH AND WITHOUT DSM

5.3.6.4.3 On Zone Substations

Refer to Graph 5-14 "Zone Substation Forecasts With And Without DSM".

Graph 5-14 compares the projected forecasts, with and without the effects of demand side management on the capacity of zone substations. The following assumptions can be made about the impact of demand side management initiatives:

- The Nihoniho transformer is forecast to reach full load at the end of the planning period, but with demand side management capacity is still available.
- The Atiamuri transformer is forecast to exceed full load at the end of the planning period but with demand side management realistic operating capacity limits are just being reached. The Plan includes an additional supply from Whakamaru in years 2022/23 which will alleviate this constraint.
- The Tawhai transformer will be at maximum loading, but demand side management off sets the urgency of the transformer upgrade.
- Gadsby Road, with demand side management, should gain extra headroom of nine years.
- The Borough transformers would be at maximum nine years earlier without demand side management. (The installation of a modular substation to the north of Taumarunui will also affect loading).
- Waitete transformer is forecast to reach full load, but with demand side management, headroom capacity is still available.



GRAPH 5-14: ZONE SUBSTATION FORECASTS WITH AND WITHOUT DSM

5.3.7 Equipment or Network Constraints Anticipated due to the Forecast Loadings for the planning period

TLC uses a network analysis program (ETAP) to predict where constraints will occur if the forecast load growth occurs. The network is modelled with the projected loadings and the program produces reports that highlight the assets within TLC's network that are likely to have unacceptable voltage levels; similarly, ETAP reports can be used for current constraints.

Table 5-11 and Table 5-12 are samples of the reports and notes that can be added for planning purposes.

ETAP REPORT			PLANNERS NOTES
Bus ID	**Nominal kV**	**Voltage (%)**	**Comments Voltage & Asset Group**
106 Bus86	11	98.11	
106 Bus87	11	98.04	
106 Bus89	11	97.37	
106 Bus848	11	99.35	
106 Bus851	11	99.16	
106 Bus852	11	99.00	
106 Bus856	11	98.92	
106 Bus860	11	97.44	
106 Esplanade	11	99.88	
210 Waitomo/ Te Kuiti Town Tie	11	97.45	
242 Oparure/Te Kuiti South Tie	11	98.67	
269 Oparure/Piopio Tie	11	96.57	
489 Whakamaru Pureora Tie	11	99.36	
505 Waitomo Hangatiki East Tie	11	99.02	
507 Spur	11	96.38	
531 Huirimu Pureora Tie	11	92.00	Huirimu Regulator in 2012/13
Bus288	11	93.69	Wharepapa regulator in 2013/14
Bus298	11	92.64	Wharepapa regulator in 2013/14

TABLE 5-11: ETAP VOLTAGE CONSTRAINT REPORT & PLANNERS NOTES

Note: ETAP can be pre-set with a colour coding for voltage levels that are outside set limits and close to limits to be highlight; in this case pink for close to 95% of the rated voltage and red for over 95% of the rated voltage.

The report indicates that sections of the network will have loadings that are below or close to 95% of the rated voltage. In the sample table above, all the sections that indicate below 95% of the rated voltage already have voltage regulators programmed into the forward plan.

ETAP REPORT				PLANNERS NOTES			
ID	**Max Amp Flow 2011**	**Forecast Amps 2017/18**	**Forecast Amps 2026/27**	**Conductor**	**Conductor Rating**	**Asset Group**	**Location**
Cable282	2.35	2.34	2.39				
Cable283	1.29	1.28	1.31				
Cable284	135.50	138.70	167.90	1-3/C Al 95	234	404-01	Matapuna. CB6063
Cable285	124.20	127.50	155.20	3-1/C Cu 7/083	165	404-01	Matapuna. Sw 1.3
Cable286	118.50	121.90	148.90	3-1/C Cu 7/083	165	404-01	Matapuna. Sw B.2
Cable287	104.30	107.90	133.20	1-3/C Cu 50	207	404-01	Matapuna. Sw 5031
Cable288	84.87	87.89	110.60	1-3/C Cu 50	207	404-01	Before Victory bridge
Cable289	79.57	82.41	104.30	3-1/C Cu 7/064	120	404-01	Sunshine Settlement
Cable290	79.57	82.41	104.30	3-1/C Cu 7/064	120	404-01	Sunshine Settlement
Cable291	68.83	71.29	91.79				
Cable292	68.83	71.29	91.79				
Cable293	44.93	46.53	53.93				
Cable294	33.00	34.18	39.62				
Cable295	14.47	14.98	17.39				

TABLE 5-12: SAMPLE OF ETAP REPORT FOR CURRENT CONSTRAINTS WITH PLANNERS NOTES ADDED

Note: Exporting the ETAP reports into Excel allows the planner to use conditional formatting to highlight information, in this case any cable or line carrying over 100 amps (TLC has loaded the information into ETAP to use cables for all conductors, both cable and overhead lines.).

The above sample table illustrates the currents expected through the conductors if the projected load growth occurs. Using conditional formatting in Excel the spread sheet can be used to highlight any conductor expected to carry over 100 Amps. This is then checked against the actual conductor's current rating to ensure the conductor is capable of carrying the normal and contingent loads forecast.

TLC uses these reports to assist in planning and identifying areas of constraint.

An analysis of the network constraints is summarised in the following sections, given the predicted system demands listed in the sections above.

5.3.7.1 Supply Points Constraints

Hangatiki

The constraining factor on the present load off-take from Hangatiki is the capacity of the two 110 kV/33 kV banks. These have a summer/winter rating of 22/24 MVA for one unit and 25/26 MVA for the other (see Section 3). The 2012 and 2027 estimates for off-take from this site are 30 and 43.45 MVA respectively. It is often difficult during day light hours to reduce load to the 22/24 MVA level to allow Transpower to remove a unit from service to carry out maintenance. A failure or a fault in a unit will mean that a number of dairy farmers, meat processors, and lime processors will have to stop production.

If the distributed generators who have applied for connection actually connect, then the impact of this problem may reduce. This is however dependent on the generators producing output through the periods when the transformer load is high. Unfortunately, this is often during summer when there is little wind or rain to power the distributed generation schemes.

Transpower is planning to renew the two transformers at Hangatiki in years 2014/15, including a redesign.

A new ripple injection plant has been installed at Hangatiki; however, it is expected that the change out of all the relays will take about 5 years and the present plants will be decommissioned in 2017 or a little later, (dependent on the rollout of advanced meters.). In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

The 725 Hz signals series resonate at some industrial sites that have power factor correction and on SWER systems. In addition to the signal attenuation effect this series resonance causes, it also can interfere with electronic equipment and has done so.

Ohakune

The capacity of the shared Ohakune GXP transformer (shared with PowerCo) was reached in 2007. (Grid emergency declared.) This was the first season of the upgraded ski field and its demand side management generation was not available.

During the 2008 year the ski field snow making needs were not co-incident with the town's accommodation peak. Things were different in 2009 and 2010. During each of these years two peaks occurred that resulted in Transpower issuing loading warnings. (The grid exit transformer was at 95% capacity.) A possible solution is for the ski field operators to run their generators; however, they are reluctant to do this given the difficulty of getting large quantities of fuel to sites high up on the ski field.

The option of bringing an additional supply out of the neighbouring Tangiwai grid exit has been included in the plan for 2012/13 year. A Tangiwai supply point will enable backup for the Ohakune site for planned and unplanned outage events.

Tokaanu

There are no capacity constraints at the Tokaanu point of supply.

National Park

Continued development at the Whakapapa ski field and National Park village will continue to drive load demands at this grid exit point. Models are saying that the grid exit transformer capacity will be adequate to the end of the planning period. It is likely a non-asset solution in conjunction with the development of the ski field will be pursued when its transformer capacity is fully utilised.

There are a number of potential hydro sites in the area that, if developed, would alter the National Park grid exit loads. Transpower has proposed work at National Park in the 2013/14 year. TLC has programmed work to coincide with Transpower's work to reduce the number of circuit breakers, reduce hazards, improve reliability and solve environmental issues.

Ongarue

The Ongarue point of supply has sufficient capacity for all likely development during the planning period. This may change towards the end of the planning period if potential hydro in the region is developed.

The connection charges for the site are high and it is possible to reduce these by rationalising the number of outgoing feeder circuit breakers. As with other sites above, Transpower has agreed to work with TLC to modernise and rationalise the site to better produce outcomes that both organisations require.

Whakamaru/Atiamuri

It is likely the capacity of the 10 MVA backup supply out of Atiamuri will be at its upper limit towards the end of the planning period. (Our load predictions are indicating this; however, it will be very dependent on the developments that take place around the Tuaropaki energy park).

The present primary load control system for the area downstream of the Whakamaru/Atiamuri supply is old and based on an injection frequency of 725 Hz. The plants themselves inject at 11 kV. Over time load has grown and the signal propagation levels have attenuated resulting in unreliable relay operation. There is also a zone substation without an injection plant. The consequence of this is little signal level downstream of this site.

A new ripple injection plant has been installed at Whakamaru GXP. It is expected that the present plants will be decommissioned after a relay rollout in 2015 (approximately; subject to advanced metering rollouts). In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

TLC has included in its Plan load control for the new point of supply at Mokai to allow peak demand load controlling and demand side management initiatives.

5.3.7.2 33 kV Line Constraints

Taharoa A and B

These lines have capacity to supply the iron sands complex at Taharoa. At present, final applications have been received for the connection of more distributed generation than the capacity of the lines.

The iron sands extraction company is also proposing to expand the present operation. A consequence of their expansion will be the continued funding of the 33 kV lines and substation. If they leave before the end of the lifecycle of the generators, then the generators will have to fund the lines.

To get the capacity the generators wish to transmit back to Hangatiki, TLC will have to apportion outputs, only accept one application or upgrade the lines. The amounts of these outputs will be heavily dependent on the control systems the generators put in place. Parts of the lines currently have an age and reliability constraint. Funding to improve these will come from the connected parties. Apart from the lines, the biggest liabilities facing the generators will be costs associated with power factor correction at the Hangatiki grid exit and protection. The generators may also decide to fund the option of upgrading one line to 110 kV.

Te Waireka and Te Kawa 33 kV lines

These two lines operate in a closed ring supplying Otorohanga. Loadings shown in the forecast are the amounts expected for each of these lines individually to supply the load. Present (n-1) security to Otorohanga with these two lines will become marginal by the end of the planning period.

Gadsby Road

The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates.

Waitete

The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates.

Gadsby/Waitete 33 including Wairere Tee

The capacity of this line will not be exceeded at the end of the planning period unless resource consents are granted for the Mokau generation scheme. If this occurs then regulators will be required to pull down the voltage. This has been programmed for 2024/25 but will depend on the timing of the proposed generation connection.

Mahoenui 33

This line has sufficient capacity for the planning period.

Whakamaru 33

This line will be reaching full capacity by the middle of the planning period. It is likely that ability to retain 11 kV voltages at zone substations fed from this line within desired limits will be lost towards end of the planning period. There are regulators programmed to be installed in the 2012/13 year and additional regulators in 2016/17 if required. Beyond this it is likely that an additional 33 kV supply will have to be taken out of Transpower or Mokai at Whakamaru.

National Park 33

It is not likely that this line will have reached full capacity by the end of the planning period.

Tuhua 33

This line will not have reached full capacity by the end of the planning period.

Nihoniho 33

This line will not have reached full capacity by the end of the planning period. If the Tatu or other coalmines in the Ohura area reopened then it is likely this line will have to be extended. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Taumarunui to Ongarue 33

This line is currently operating at close to full capacity if generation is not available. There will be no need to alter the configuration during the planning period provided the generation continues to be available. The line has a reliability and low risk hazard constraint caused by its age and inherent low strength design.

Tokaanu/Kuratau

The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Kuratau/Taumarunui 33

The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Kuratau/National Park

The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Turangi 33

The capacity of this line will not be exceeded at the end of the planning period.

Lake Taupo 33

This line will not have reached its full capacity by the end of the planning period. The line was originally totally constructed of a small diameter conductor that was inadequate for the fault capacity of the Tokaanu grid exit. Most of the line has been reconstructed using mink conductor; however, there is one section left still that has hazard constraints at the crossing of the Tongariro River. Work is planned to install taller poles and cover the conductors across the river to help alleviate the hazard of the bare live wires to people trout fishing.

5.3.7.3 33 kV Zone Substations and Transformer Constraints

Taharoa

Increased industrial load for iron sands extraction will mean it will be necessary to reinstall fans on the Taharoa units. Other modifications to switchgear and metering will be needed at the site to accommodate the customers' expansion requests in the planning period.

Te Waireka

The existing transformers will have adequate capacity to the end of the planning period. Present (n-1) capacity is lost during the planning period. There is a part light load back up from the 11 kV network. The site has indoor switchgear with a single 11 kV bus bar without bus sectioning. Fault currents are also too high for close-in downstream equipment.

Modifications for the site are included in the planning period estimates. Additional backup will likely come from modular substations installed at industrial installations. Increased capacity to relieve one feeder's loading in particular will come through the installation of a modular substation and a 33 kV extension during the latter half of the planning period.

Te Anga

The load on this transformer will slowly grow as the seaside settlements at Marokopa and Te Waitere develop. The summer load at the beach settlements are at a time when the connected distributed generation is at its lowest output.

Mahoenui

The existing transformer will be able to supply adequate capacity throughout the planning period. Part backup only is available if the transformer fails. Beyond this planning period, it is likely that the loading on this transformer site will reduce if the 33 kV line is extended past Mahoenui towards Mokau to supply an additional coastal development.

Oparure

The existing transformer will be able to supply adequate capacity throughout the planning period. This transformer principally supplies one large industrial customer in a quarry. If the site is expanded, the transformer will possibly need upgrading.

Hangatiki

The existing transformer will not have adequate capacity to the end of the planning period. Limited backup is available from the 11 kV network. An additional modular substation at a lime processing plant has been included in the plan to provide adequate capacity.

Gadsby Road

The capacity of the existing transformer will be adequate for the planning period.

Wairere

The existing transformers will have adequate capacity to the end of the planning period. Very light load backup is available. This site is integrated with a distributed generation connection. An (n-1) capacity is only available at light load times.

Waitete

The site has adequate transformer capacity. It has ageing single bus bar 11 kV switchgear without any bus sectioning. The switchgear is backed up with a low cost ring-main unit arrangement. To take the industrial pressure off the site, large users are being encouraged to install modular substations at their plant sites. Fault current levels are also a constraint. Light load back up is available. Modular substations at industrial sites have been included in planning estimates.

Maraetai

The capacity of the existing transformer will be exceeded in the earlier part of the planning period. It will have to be upgraded or else additional modular substations will have to be installed in the area. Light load backup is available, but the area has a growing dairying load. A modular substation closer to the major load has been included in planning estimates. This may be alleviated partly if the proposed generation into the Pureora feeder goes ahead within the planning period.

Atiamuri

The existing transformer is predicted to be up to capacity midway through the planning period. It is likely that options for backing up this transformer and its unique connections will be developed by the end of the planning period.

The exact detail for this requirement is very difficult to predict at this time given the uncertainty of development at the Tuaropaki energy park, but will likely involve taking more capacity from the internal network. If this occurs it is unlikely that the Atiamuri transformer would be upgraded as a consequence. An allowance for upgrading has not been included in estimate other than putting fans on the existing unit.

Arohena

The existing transformer will be able to supply adequate capacity throughout the planning period. Light load backup only is available to this dairying area. The site may not meet dairy customers' security expectations and will be subject to discussion with stakeholders.

Marotiri

Some of the load on this substation has been shifted to a new substation at Kaahu; this extends the existing transformer capacity to supply to the end of the planning period, though a significant upsurge in dairying could change this.

The Marotiri load will further be affected by load at the Miraka Milk plant. The transformer will be called on to back-up the energy park when the Mokai geothermal plant output is not available. At the time of writing further discussions are underway with Tuaropaki re the future development that will be needed in this area.

Kaahu

A modular substation of 2 MVA was installed in 2009 that will carry the load until the end of the planning period.

The unit will also be used to back-up the Miraka milk plant in parallel with the Marotiri transformer when the Mokai geothermal generation is not available.

Borough

The existing transformers will have marginally adequate capacity to the end of the planning period. Very light load backup is available. Further improved reliability and backup has been provided for in the latter half of the planning period with an additional modular substation to the north of the site and to re-conductor a section of line at Manunui. This reduces capacity requirement on the transformers to the end of the planning period and improves supply to the area. It also improves an environmental constraint as Borough has the potential to flood.

Manunui

The existing transformer will be able to supply adequate capacity throughout the planning period. Light load backup is available.

Nihoniho

The event that will cause a load increase will be the re-establishment of a coalmine at Tatu. If this coalmine is not re-established the Nihoniho capacity needs will decline with no other industrial or commercial operations in the area. Load estimates include an allowance for the coalmine and, as such, the site will need upgrading during the planning period. The site has a hazard constraint caused by its enclosure design. The site also has a landowner constraint and at some stage TLC will possibly be evicted from the site. (Site is in a DOC scenic reserve.)

Tuhua

As per Nihoniho except that the demand on this site will remain close to the present. The site has a medium to low risk hazard constraint caused by its design and closeness to the neighbouring houses. (This risk has reduced as fences have been moved by the adjacent landowners in recent times.)

National Park

The existing transformer will be able to supply adequate capacity through to the end of the planning period. The switchgear configuration at this substation is not ideal and the site has a reliability and medium risk hazard constraint. (Hazard constraint associated with fence and load control plant.) Work at this site will be co-ordinated with Transpower as the site is located at the GXP.

Otukou

The load will not exceed capacity during the planning period. The site has a medium risk hazard constraint caused by its design and age.

Tawhai

The existing transformer will be fully loaded by the end of the planning period. Light load backup is available. Expansion at the ski field and mountain village area beyond 5 MVA will mean the transformer has to be upgraded or additional units have to be brought in. An additional unit has been included in planning estimates.

Kuratau

The existing 3 MVA transformer will not be able to provide adequate capacity throughout the planning period. The oil tests are indicating that there is a condition constraint with this transformer. A backup has been installed in 2009 with a capacity of 1.5 MVA. It will be necessary for this to stay in place until 2022 when it is planned to install an additional modular substation at Waihi to provide an improved supply arrangement for the area and supplement capacity.

Turangi

The existing transformers will have adequate capacity to the end of the planning period. The site has hazard and reliability constraints. Two modular substations have been commissioned during the recent planning period to provide back up to the site at all but heavy load times. It is planned to increase load on the modular substations and relocate one of the existing transformers to Tawhai during the planning period.

Kiko Road

The existing transformer will be able to supply adequate capacity throughout the planning period. No backup is available if the transformer fails other than by-passing the site and operating the 33 kV system at 11 kV. The site has a low risk hazard constraint due to the fence design. (Area was in a forest but it has been subsequently developed as a housing subdivision. The fence and site was not designed to be part of a residential development.)

5.3.7.4 Distribution Feeder Constraints

Table 5-13 to Table 5-18 list the distribution feeders and the constraints. Note: The hazards in these tables are being controlled as part of the asset management process and addressed in this plan. The references to the constraints are explained in notes following the tables. The feeders have been listed under each point of supply.

HANGATIKI POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Aria	OK	3	3	3	None within this planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators. SWER lines.
Benneydale	OK	4	3	2	There are 4 regulators on this feeder and distributed generation. Without generation the voltage can dip at the end of rural spurs.	Very long feeder with industrial and rural customers. Distributed generation, Universal Beef Packers switch gear and SWER lines.
Caves	OK	3	3	3	Due to the light conductor the end of long rural spurs are constrained.	Long spans towards end. SWER lines.
Coast	OK	4	4	3	Marokopa and the Kiritehere could see constraint if the load continues with the same growth factor within the next four years due to small conductor size.	Rural feeder with distributed generation and SWER system.
Gravel Scoop	OK	1	4	2	Gravel Scoop is at its upper limits with a predicted growth factor of 1.2% will see constraints in the next four year period.	Rural supply with dairying load. High fault currents near zone substation.
Hangatiki East	OK	1	2	2	Due to a large lime industrial site this feeder is at its upper limits.	Industrial & dairying load.
Mahoenui	OK	4	3	3	Voltage at end of long rural spurs at upper limits.	Long rural feeder. Reliability constrained by long spans and polluted insulators. SWER systems.
Maihiihi	OK	3	4	2	Two regulators on this feeder providing voltage support. Loading at upper limits.	Long urban and rural feeder with mainly dairy farming load. High fault currents near zone substation.
McDonalds	OK	1	4	2	Regulator installed 2011/12 year.	Rural feeder with lime works connected. High fault currents near zone substation.

HANGATIKI POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Mokau	OK	4	4	4	Two regulators on this feeder. Voltage starts to decline through the Taumatamarie area. Feeder at upper limits.	Long rural feeder with two regulators installed. Significant amount of overhead line in exposed coastal environment. A number of coastal towns with proposed subdivisions on hold. Four separate SWER systems into the remote rural areas.
Mokauiti	OK	4	3	3	SWER systems at end of feeders put voltage at it upper limit.	Rural feeder. Reliability constrained by long spans and polluted insulators. Two SWER systems into remote areas.
Oparure	OK	3	4	2	None within this planning period.	Long rural feeder with fertiliser polluted insulators.
Otorohanga	OK	1	4	4	None within this planning period.	Mainly urban supply with some very rugged rural spans once it leaves urban area. High fault currents near zone substation. Number of ground mounted transformers.
Piopio	OK	3	3	3	This feeder is at its upper limit, growth in the area could see Piopio township constrained in the next four years.	Rural feeder. Reliability constrained by long spans and polluted insulators.
Rangitoto	OK	4	3	2	Regulator installed in 2011/12 year.	Long feeder with industrial and rural loads. Has one small SWER system. Recent line renewal has strengthened lines.
Rural	OK	4	4	3	None within this planning period.	Small coastal feeder. Has a metering constraint.
Te Kuiti South	OK	3	2	2	None within this planning period.	Urban and rural supply with a number of ground mounted transformers.
Te Kuiti Town	OK	OK	1	1	None within this planning period.	Mostly urban supply. Many ground mounted transformers.
Te Mapara	OK	3	3	3	None within this planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators. SWER systems.
Waitomo	OK	1	3	1	None within this planning period.	Urban and rural supply. Has large sawmill connected.

TABLE 5-13: CONSTRAINTS ON FEEDERS SUPPLIED BY HANGATIKI POS

WHAKAMARU POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Huirimu	OK	4	3	2	This feeder is at constraint now, estimated 40% of the year which occurs during the dairying season.	Rural feeder supplying dairy load.
Mangakino	OK	OK	2	2	None within this planning period.	Supply to ex dam construction town. Low 2 pole structures and low voltage in poor condition.
Mokai	OK	4	3	3	Voltage constraint along Karangahape Road to dairy farms on Kawakawa Road. Regulator on other leg of feeder.	Rural feeder with dairying, subdivision and industrial load growth.
Pureora	OK	5	3	2	Two regulators on this feeder. If the load increases at the end of the feeder (i.e. Crusader Meats), this will constrain the feeder.	Long rural feeder with meat processor on end.
Tihoi	OK	4	3	3	None within this planning period.	Rural feeder with growth. SWER system.
Whakamaru	OK	3	3	2	This feeder is at its upper limits for voltage. This feeder is used as back up supply for Pureora, Tihoi or Tirohanga feeders. Backup can only be done outside milking times.	Rural feeder supplying dairy load. Old cabling and lack of switchgear in underground system at what was the hydro village at Whakamaru.
Wharepapa	OK	4	3	4	This feeder recently had a regulator installed. However, continued dairy growth in the year has seen the need to program additional regulators for 2013/14 year.	Long rural feeder supplying dairy load.
Tirohanga	OK	3	3	2	None within this planning period.	Rural feeder with many trees along route.

TABLE 5-14: CONSTRAINTS ON FEEDERS SUPPLIED BY WHAKAMARU & MOKAI POS'S

ONGARUE POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Hakiaha	OK	OK	3	3	None within this planning period.	Mostly urban feeder in Taumarunui with many GMT substations.
Manunui	1 (SWER)	4	3	3	Long small conductor SWER lines.	Rural feeder with a number of SWER systems.
Matapuna	OK	2	3	3	Due to small cable sizes this feeder is at its upper limits.	Mostly urban feeder in Taumarunui. Small cable.
Nihoniho	OK	5	4	4	None within this planning period.	Old feeder into very remote rugged country with SWER.
Northern	OK	4	4	3	Voltage constrains occurring for rural area at end of feeder. May constrain closer to the edge of Taumarunui with lifestyle developments.	Long rural feeder SWER systems. Old switchgear.
Ohura	OK	5	4	4	None within this planning period but will depend on Tatu mine.	Old feeder into very remote rugged country. Five separate SWER systems.
Ongarue	5 (SWER)	5	3	3	Voltage drops due to small conductor have put this feeder at its upper limits. SWER systems also at upper limits.	Rural feeder in rugged remote country with high current SWER systems.
Southern	OK	4	3	3	Without generation this feeder can constrain just south of Owhango. SWER transformers can constrain during peak loadings.	Have a number of closely spaced SWER and 3 wire systems. Six separate SWER systems supplying remote areas. Distributed generation.
Tuhua	1 (SWER)	5	3	3	None within this planning period.	Rural feeder in rugged remote country. High current SWER systems.
Western	1 (SWER)	4	4	4	At the upper limits, the growth of lifestyle blocks close to Taumarunui may see this feeder with voltage constraints in the next 4 - 5 years.	Long rural feeder with high current SWER systems.

TABLE 5-15: CONSTRAINTS ON FEEDERS SUPPLIED BY ONGARUE POS

TOKAANU POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Hirangi	OK	OK	1	OK	None within this planning period.	SWER feeder close to Turangi.
Kuratau	OK	3	4	4	No constraints at present, lake side development may change this situation.	Feeder supplying Kuratau holiday area. Underbuilt and U/G systems. Long SWER systems. Low strength poles, renewal programme has replaced many of these poles.
Motuoapa	OK	2	2	2	None within this planning period.	Low structures & LV systems. Many improvements to minimise/eliminate hazards, more needed.
Oruatua	OK	3	2	2	None within this planning period.	SWER systems. River crossing over popular trout stream. Low structures. Many improvements have been completed. More are needed.
Rangipo / Hautu	OK	2	2	3	None within this planning period.	Many improvements to eliminate/minimise hazards; more needed.
Tokaanu	OK	OK	2	1	None within this planning period.	Many improvements to minimise/eliminate hazards.
Turangi	OK	OK	4	2	None within this planning period.	Ground mounted transformers in inadequate enclosures and old switchgear.
Waihaha	OK	4	4	4	No constraints at present, development on Karangahape Road will change this situation.	Feeder with long SWER systems connected. Many of the low strength poles have been replaced in the line renewal programme.
Waiotaka	OK	OK	1	1	None within this planning period.	Short feeder supplying Hautu Prison and SWER system to a Māori incorporation farm.

TABLE 5-16: CONSTRAINTS ON FEEDERS SUPPLIED BY TOKAANU POS

NATIONAL PARK POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Chateau	2	4	2	1	There are 2 regulators on this feeder providing voltage support.	Switchgear on the mountain. Many improvements to eliminate/minimise hazards; more needed.
National Park	OK	3	3	4	Remote lines with small conductor south of National Park constraint at heavy loads.	Hazard concerns include National park switchgear and long spans of single phase along SH4. Environmental concern in World Heritage Park.
Otukou	OK	3	3	3	None within this planning period.	Heavily forested, most of feeder is SWER.
Raurimu	1 (SWER)	5	3	3	Three phase voltage is starting to drop away at Kaitieke just before SWER isolating transformers. SWER transformers are overloaded at peak loading times.	Feeder with three very long SWER systems into remote rugged country. These systems have high current loadings.

TABLE 5-17: CONSTRAINTS ON FEEDERS SUPPLIED BY NATIONAL PARK POS

OHAKUNE POINT OF SUPPLY						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Ohakune Town	OK	1	3	4	The small conductor and heavy loads over the ski season have put this feeder at its upper limits.	Work needed to remove hazard constraints with LV and switchgear and to meet growth. Conductor size small in some areas.
Tangiwai	4	3	3	3	One regulator installed at Tangiwai. At heavy loading this feeder constrains from the town's boundary.	Renewal work over the last few years to improve pole strengths. Snow area.
Turoa	OK	3	3	2	Three regulators installed on this feeder.	Supply to ski fields. Has old switchgear and requires more 11 kV switches for safe operation.

TABLE 5-18: CONSTRAINTS ON FEEDERS SUPPLIED BY OHAKUNE POS

Current and Access Constraints

Current constraints are determined by using the network analysis program to forecast the expected currents on conductors, these are then checked against the existing conductors rating. The constraint priorities in Table 5-19 to 5-22 are defined on a scale of 1 to 5, five being the most concerning. The definitions of priority are set out in these tables.

CURRENT CONSTRAINTS	
Constraint Grade	**Current Constraints on 11 kV Feeders for predicted loads over 15 year planning period**
1	Current of 100% of a section conductor rating.
2	Current of 110% of a section conductor rating.
3	Current of 120% of a section conductor rating.
4	Current of 130% of a section conductor rating.
5	Current of 140% or greater of a section conductor rating.

TABLE 5-19: CURRENT CONSTRAINTS

Access constraints are determined from the line inspection information and local knowledge.

ACCESS CONSTRAINTS	
Constraint Grade	**Access Constraints on 11 kV Feeders**
1	Up to 20% of the feeder must be fault patrolled and accessed with a helicopter.
2	Up to 40% of the feeder must be fault patrolled and accessed with a helicopter.
3	Up to 60% of the feeder must be fault patrolled and accessed with a helicopter.
4	Up to 80% of the feeder must be fault patrolled and accessed with a helicopter.
5	Up to 100% of the feeder must be fault patrolled and accessed with a helicopter.

TABLE 5-20: ACCESS CONSTRAINTS

Reliability Constraints

Reliability problems due to age, construction, span lengths, tree numbers, numbers of alternative feeds, numbers of reclosers, other automated controls, known fault current problems, distances from depots, amount of feeder that is a radial feeder, local terrain, i.e. how rugged and remote the area is, previous history and likely problems have been considered to assign a reliability constraint.

The severity of these constraints is listed as in Table 5-21.

RELIABILITY CONSTRAINTS	
Constraint Grade	**Reliability Constraints on 11 kV Feeders**
1	Above issues are expected to cause problems or likely to cause problems every 2 years.
2	Above issues are expected to cause problems or likely to cause problems every 12 months.
3	Above issues are expected to cause problems or likely to cause problems every 6 months.
4	Above issues are expected to cause problems or likely to cause problems every 3 months.
5	Above issues are expected to cause problems or likely to cause problems monthly.

TABLE 5-21: RELIABILITY CONSTRAINT

Note: TLC has recently introduced better software to calculate line strengths when data come back from line inspections. Assessments are becoming more accurate as better data flow through.

Extreme Weather Constraints

EXTREME WEATHER CONSTRAINTS	
Constraint Grade	**Extreme Weather Constraints on 11 kV Feeders**
1	Winds greater than 40 km/hr.
2	Winds greater than 60 km/hr.
3	Winds greater than 80 km/hr.
4	Winds greater than 100 km/hr.
5	Winds greater than 120 km/hr.

TABLE 5-22: EXTREME WEATHER CONSTRAINTS

Constraints due to extreme weather conditions rise as wind speed accelerates. For example, winds between 40 - 60km/hr have little effect on the network, whereas wind speeds above 80km/hr start to have a significant effect on our 11 kV feeders.

5.4 Policies on Distributed Generation

5.4.1 Policies for the Connection of Distributed Generation

5.4.1.1 Distributed Generation: General Policies

The policy on distributed generation is to allow the connection of distributed generation where it meets the costs of dedicated assets. The criteria for connection includes protection against the generation causing network hazards and impacting on network operating and other standards, including existing revenue flows.

TLC will encourage investors to provide network support by providing financial incentives aligned to the network savings that distribution generation produces.

All costs associated with collective and individual distributed generation connections shall be funded by the generators in accordance with the Electricity (Distributed Generation) Participation Code.

5.4.1.2 Capacity Policy

The capacity of generation that can be connected to any part of the network is determined by a number of factors. The most significant factor that affects capacity is the voltage rise when the network is in a normal state during an RCPD period with the plant operating at unity power factor. Policy is that the voltage rise should not exceed 2% (for 11 kV and LV networks) above the normal voltage. TLC will follow the requirements of the Codes in implementing this policy.

5.4.1.3 Applications for Connection Policies

The processes for considering applications follow those detailed in the Electricity (Distributed Generation) Participation Code. The fees charged for considering applications are those prescribed in the distributed generation regulations. The generators have to fund the full costs associated with preparing and submitting their initial and final applications.

Much of the work for new connections involves investigating options for capital upgrades so that cost indications can be given to potential investors. These upgrades often go deep into the network and can be complex.

In at least two recent cases, several parties wish to connect to the existing lines that only have capacity for one plant. Issues such as this pose questions such as deciding which one should be connected or how costs should be allocated. TLC's experience is that distributed generation issues often absorb considerable engineering time. This input must be funded from charges on an on-going basis for the connection of distributed generation.

5.4.1.4 Charging Structure for Distributed Generation Policies

There are two possible options for generators if the requirements of the Electricity (Distributed Generation) Participation Code are followed. These are the default regulated terms as listed in the Electricity (Distributed Generation) Participation Code, or a fixed fee approach. The regulated terms result in uncertainty to generators by having the provision for an annual reset on pricing and no capacity rights. The fixed fee is a contract outside of the Participation Code whereby TLC, for a set fee, can give the generators more certainty in pricing and, for a fixed amount, take the uncertainties away from generators.

Most of the generators connected to, and wanting to connect to, the TLC network want the fixed fee approach provided the charges are realistic. The main reason for this is that the investor generators do not have technical knowledge and they want all of the complex electrical engineering taken off their hands while they focus on the environmental and mechanical issues associated with running plant.

TLC on the other hand is exposed to increased risk with this flat fee approach because of the uncertainty, for example, the possibility of complex grid exit power factor liabilities and the implications of operating outside the Electricity (Safety) Regulations.

The charging principle for the fixed fee and regulated approach is based on the following components:

A fixed fee for the capacity connected to cover the cost of administration, engineering and system operation associated with the connection of distributed generation.
A variable component with credits and charges associated with network benefits and non-benefits.

Credits are for:

- Transpower demand avoidance.
- Reduction in SAIDI minutes/SAIFI frequency. If plant is positioned in a place on the network, and has suitable controllers that will actually achieve SAIDI/SAIFI reduction, then TLC will pay a credit.
- Reduction in system losses (these payments will come from the market).
- Deferring of any capital expenditure by removing network constraints.

Charges are for:

- Inability to auto-reclose. TLC will instigate this charge if it cannot auto reclose within 5 seconds of a line tripping.
- Costs of power factor improvement required to be funded by TLC.
- Dedicated assets.
- Engineering time when a plant is modified, expanded or has an on-going operational problem.
- Any costs for destroyed appliances due to incorrect operation of the plant. (These will usually be direct claims from insurers or the owners of destroyed equipment.)

5.4.1.5 General Technical Issues with Distributed Generation that cause the need for Site Specific Conditions and Polices

As discussed in other sections of this plan, TLC has a long history of experience with distributed generation connected to the network. TLC's experience with distributed generation has highlighted the following issues:

<u>Power Factor</u>

The laws of physics are such that as power is transmitted through networks there are three components; active (kW) and reactive (kVAr) and apparent (kVA). This passage of power is modelled by a triangle as shown in Figure 5-5.

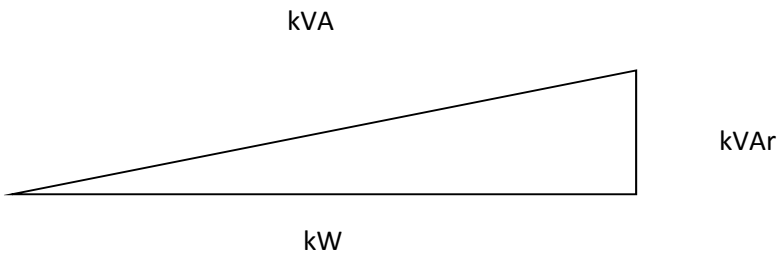


FIGURE 5-5: POWER TRIANGLE

Whenever distributed generation is connected, active power is injected. In rural networks such as TLC's it is generally difficult to inject reactive power because of voltage rises. Figure 5-6 illustrates how the triangle is modified when distributed generation is connected.

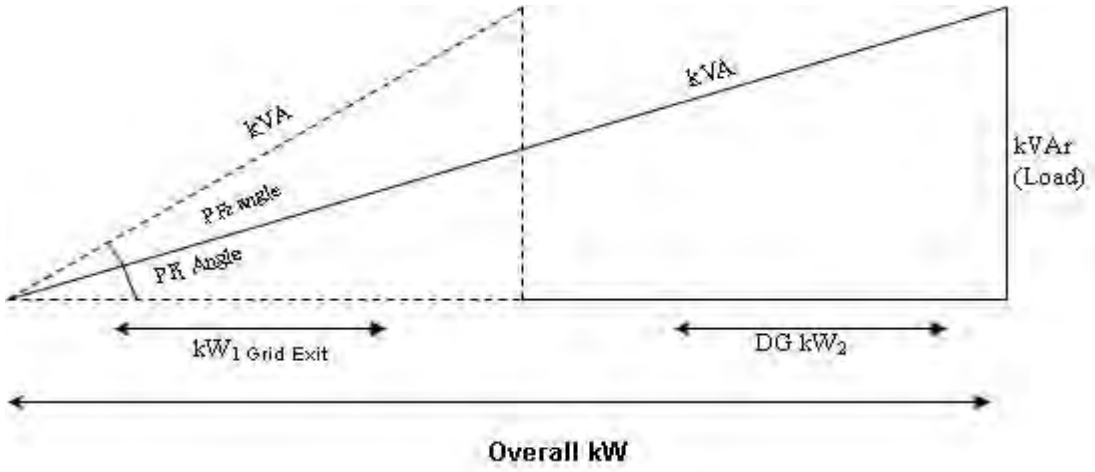


FIGURE 5-6: ILLUSTRATION OF EFFECT OF DISTRIBUTED GENERATION

Overall kW, kVA and kVAr are the components customers take out of a grid exit as shown by the solid lines. This diagram assumes that no distributed generation is connected. If distributed generation is connected and injects DG kW2, then the triangle is modified and becomes that shown by the dotted lines. The effect is that the power factor angle becomes greater; (PF2 angle within dotted triangle as opposed to PF1 angle within solid lines).

In the case of Hangatiki, DG kW2 comes from Wairere Falls, Mokauiti, Mangapehi, Marokopa, Speedys Road and other small generators.

Stability

Distributed generation does cause voltage and line tripping stability problems. TLC has investors' plant connected to the network that fights with other investors' plants on line tripping. This causes voltage and frequency swings on islanded network sections that have destroyed electronic appliances.

Resonance

TLC has had one case where the way an investor's plant was connected turned a 40km long 11 kV feeder into a sub 50 hertz oscillator. This had the potential to destroy appliances in at least 500 homes.

Current Flows/Protection

The plant characteristics and the way they are connected can cause various negative and zero sequence currents. TLC has had a number of cases where the zero sequence currents have biased and affected earth fault protection. Fault current levels also vary dependant on whether or not generation is connected. This makes protection settings more complex.

Auto Reclosing

Distributed generation plant can be damaged when a feeder is auto-reclosed. As a network company, SAIDI minute performance is a major measure. Distributed generation can be counter-productive to auto-reclosing to improve SAIDI performance.

Voltage Regulation

Distributed generation adds complexity to voltage control schemes. Distributed generation tends to run only when fuel sources are available. Often this time does not coincide with heavy feeder loadings. Distributed generation can cause a voltage swing that requires the installation of additional voltage regulators to hold network voltage. (Historic voltage control regulators typically have a 15% boost 5% buck range and the buck range sometimes has to be extended by the addition of extra regulators.)

Metering

Technically, metering is simple. However analysts reconciling distributed generation in the electricity market often have difficulty understanding the issues. Star points on the HV side of metering transformers can also cause interference problems with power systems. (TLC has experienced ferroresonance).

Islanding (Operate Isolated from Grid Connections)

Synchronous machines will island (or try to). When they island, TLC's experience is that frequency and voltage are not accurately maintained. This has destroyed electronic equipment and this has to be protected against.

Rules for Liability

Distributed generation and the interaction with the network is complex. When things do go wrong, electronic appliances can be destroyed. There are currently no rules for clearly determining these liabilities.

Loss Factors

Distributed generation connected to networks can reduce losses. They can also substantially increase losses and swing between the two extremes as network load changes. The electricity market requires a single figure for a loss factor. Calculating this is complex especially where there are a number of generators connected.

Self-Excitation

Rotating induction plant will self-excite when injecting into lightly loaded lines. It is important to get these machines quickly disconnected when they become isolated on a section of network.

Harmonics

At this time TLC is not experiencing any harmonic problems associated with distributed generation, but it is monitoring inverter sites. With the diverse TLC network, the risk potential for issues related to harmonics is high.

Voltage Flicker

As per harmonics section above. TLC has to impose conditions and polices for applications to overcome these effects. These tend to be site specific.

5.4.1.6 Effects of Power Factor Impeding Future Connections of Distributed Generation

Detail was included above on the theory associated with the effects on grid exit power factor of distributed generation. Figure 5-12 illustrate an example based on actual data from the Hangatiki grid exit.

Figure 5-12 includes blue dots for every half hour during the year August 2009 to September 2010. Figure 5-13 shows the periods that Electricity Authority rules, Part F, say must be greater than 0.95 during RCPD periods.

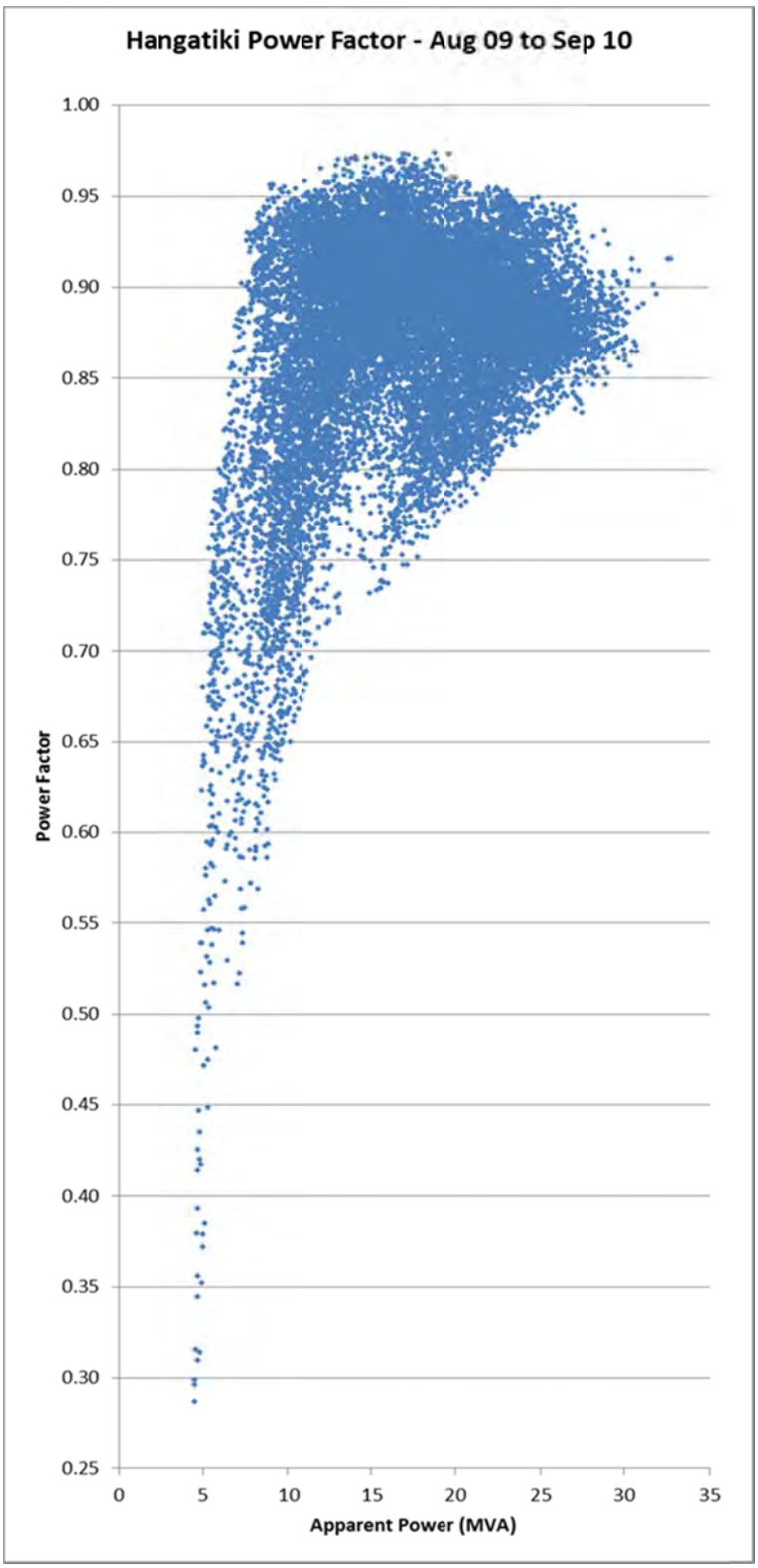


FIGURE 5.12: HANGATIKI POWER FACTOR - FULL YEARS DATA

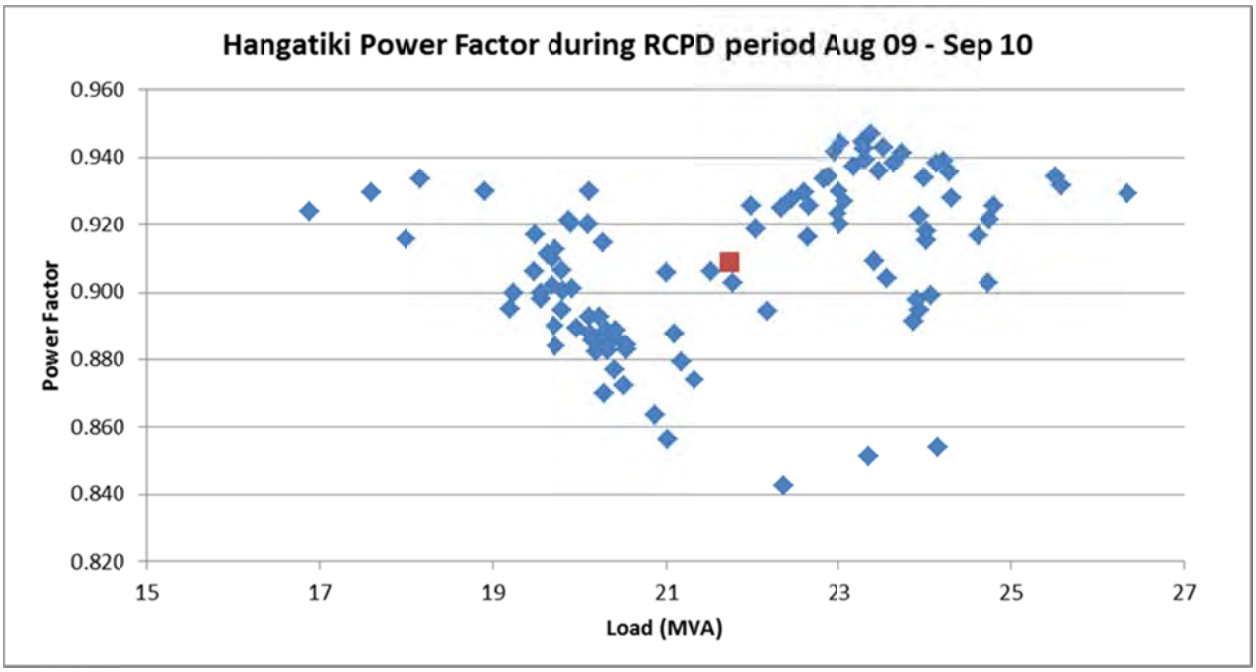


FIGURE 5.13: HANGATIKI POWER FACTOR AT 100 RCPD PEAKS

Figure 5-13 shows the power factor is rarely above 0.95. It also shows that at the peak times when the codes apply, Hangatiki power factor can get down to 0.84. This is being caused by the existing distributed generation.

As a comparison, Figure 5-14 shows the Ohakune power factor, which is above 0.95. Ohakune does not have distributed generation connected.

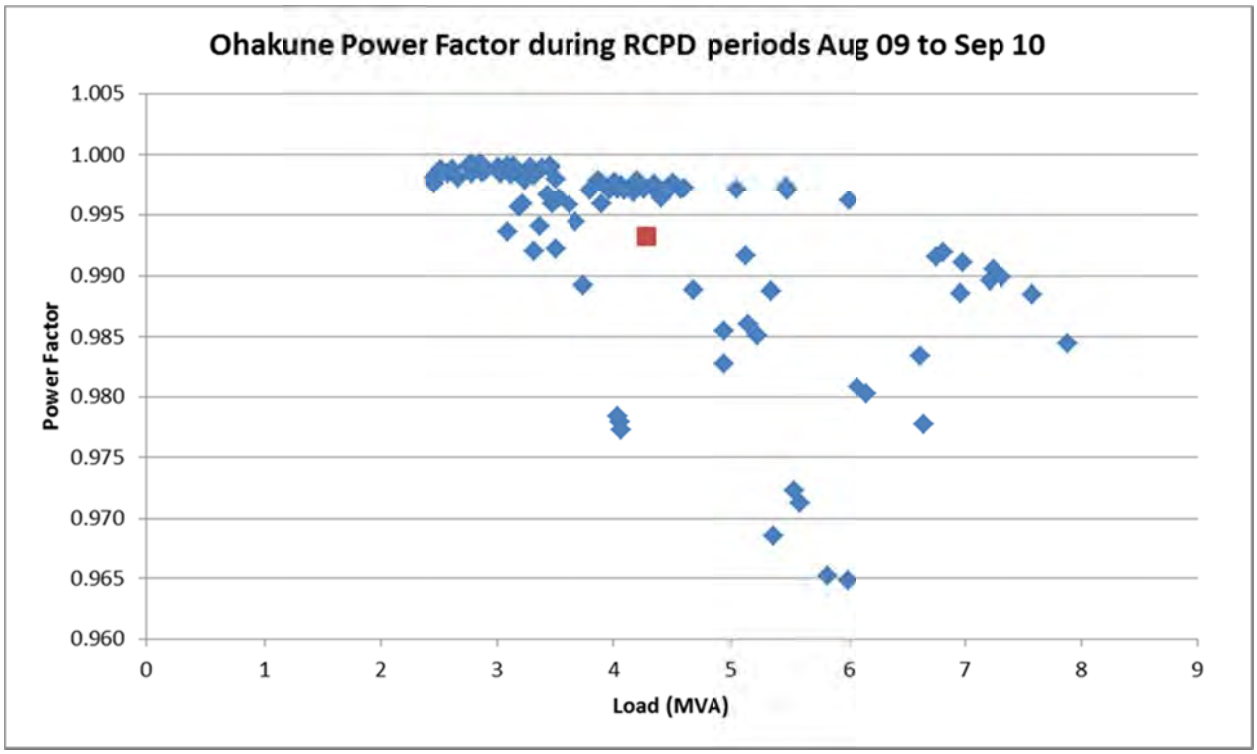


FIGURE 5.14: OHAKUNE POWER FACTOR STUDY

(Figures 5-12, 5-13 and 5-14 are based on data from the Electricity Authority 2011 RCPD by Connection Location.)

The intent of present documents produced by the Electricity Authority is to pass on the costs of correcting to 0.95 or unity at grid exits to network companies. Network companies have to recover this cost from somewhere. They have two choices: load taking customers or generators. Load taking customers are encouraged by TLC's demand based charges to correct power factor. Many do and are operating at 0.95 or better.

The generators could pay, but this will effectively penalise generators connected to distribution networks as opposed to the transmission grid. It also defies the intent of government policy to encourage distributed generation.

Given this difficult situation the solutions range from ignoring the power factor issue as has happened over the last eighty years or working towards a full reactive power market. The full reactive power market would be a good outcome as it would place a full value on reactive power. It would encourage the generation of this and, in an ideal world, allow greater value to be placed on demand side active power generation. Customers would be free to generate reactive power similar to that for active power.

While this concept is good, the technical issues are not so straightforward. For example, resonance is always a possibility around capacitor sites, either from harmonics or at the fundamental frequency. Any such market would also be complex and add overall cost to the industry.

The capacity of generation that can be connected is heavily influenced by reactive power flows. The suggested solution to this issue is to focus on reactive power flows at grid exits, not power factor. The amount of reactive power that should be allowed at a grid exit should be that which would flow if no generation was present. The amount of generation capacity that could be connected would then be more defined, i.e. the amount that, if it operates at unity, would not cause excessive voltage rises on that part of the network.

5.4.2 Impact of Distributed Generation on Network Development Plans

5.4.2.1 Existing Generation

A summary of the existing known distributed generation connected and injecting into the network is listed in Table 5-23.

Machine	Nameplate (size (kW))	GXP Load Support	Machine	Nameplate (size (kW))	GXP Load Support
Kuratau 1	3000	Ongarue[1]	Wairere 1	450	Hangatiki
Kuratau 2	3000	Ongarue[1]	Wairere 2	250	Hangatiki
Piriaka 1	1000	Ongarue	Wairere 3	900	Hangatiki
Piriaka 2	250	Ongarue	Wairere 4	3000	Hangatiki
Piriaka 3	250	Ongarue	Mokauiti 1	1000	Hangatiki
Moerangi 1	70	Ongarue[1]	Mokauiti 2	600	Hangatiki
Moerangi 2	70	Ongarue1	Mangapehi 1	1500	Hangatiki
Moerangi 3	15	Ongarue[1]	Mangapehi 2	1500	Hangatiki
Marokopa 1	35	Hangatiki	Carters	2	Ongarue2
Marokopa 2	35	Hangatiki	Waihi	0.7	Tokaanu[2]
Speedys Rd	2200	Hangatiki	Maunsell	2	Hangatiki2
Mangaotaki	200	Hangatiki	Trout Hatchery	2	Tokaanu[2]

TABLE 5-23: EXISTING KNOWN DISTRIBUTED GENERATION MACHINES

Notes:

1. *Ongarue is the GXP that these generators generally support; however, they can be switched to support National Park or Tokaanu.*
2. *These generators do not produce sufficient generation to affect the network loadings.*

In addition to this there are currently four approved final applications.

TLC also owns a mobile generator and injection transformer that is used to reduce planned and unplanned SAIDI events. The unit is also regularly used to support network voltage when only limited capacity back feeds are available.

5.4.2.2 Network Support

TLC has two mobile capacitor banks that are used to support network voltages during planned and unplanned events.

Hire generators are also used from time to time to support the network.

TLC is also investing in the development of distributed generation through a wholly owned subsidiary called Clearwater Hydro.

TLC is also looking at running its existing small support generator into the network during periods of high spot prices while fuelled by waste transformer oil to further increase its utilisation.

5.4.2.3 Projects Directly Affected by Proposed Distributed Generation not going ahead

The following projects may be affected by distributed generation:

- Voltage regulators on the Wairere/ Gadsby 33 kV line.
- Upgrade of Taharoa A 33 kV Line.
- Second voltage regulator on Whakamaru 33 kV line.
- Hangatiki point of supply upgrade. The present transformers at the Hangatiki grid exit do not have n-1 capacity. It has been assumed that distributed generation capacity will grow and restore the n-1 capacity at Hangatiki (along with demand side management effects). If this does not take place an investment contract will have to be entered into with Transpower midway through the planning period to increase the capacity of the supply point transformers.
- Waihi modular substation is dependant of the re-development of the hydro site at Waihi near Kuratau.

5.5 Policies on Non-Network Solutions

5.5.1 Non-Network Solutions processes

The general processes that TLC applies to identify and pursue non-network alternatives to its plans include:

- Price to ensure customers are aware of the cost of their:
  - » Capacity;
  - » Peak demand;
  - » Dedicated assets.
- This ensures customers are financially motivated to look at options that drive their network and non-network decisions, i.e. generators versus grid connection: gas versus the use of electrical energy.
- A high-level look at the alternatives and advice to the customer on these. Where the work involves renewals, cumulative capacity, hazard control or reliability development, the options for both network and non-network options are looked at.
- The option selected is based on the criteria of optimum cost and planning risk.
- There are a number of customers who select alternative power supplies for new connections.
- Technologies that can provide the energy intensity required for activities such as continuous water pumping and dairying are often more complex and backed up by diesel generators.
- A number of customers use single phase to three phase converters or generators to milk and the existing supplies to cool milk when supply capacity is not available. This typically occurs when there is only a single phase supply in the area.
- Financial analysis based on regulatory asset values and Commerce Commission return guidelines are completed for most capacity upgrade proposals. This analysis may include several engineering solutions including non-asset approaches such as the use of generators to provide short term demand until growth provides a stable income platform to fund asset network upgrades.
- Encourage the development of distributed generation to alleviate capacity constraints. Part of this encouragement is mostly given by the pricing structures put in place.
- Any customer who has a critical load is encouraged to make provision for its own standby generation and/or install generation to meet peak demand. For example during power outages:
- Ruapehu Alpine Lifts (RAL) has generators installed so that in the case of a power failure they are able to run the lifts to clear people stranded on the chair lifts.
- A number of dairy farms have generators that they run from the tractor Power take off (PTO) which enables them to continue milking in times out power outages. See Figure 5-7, which illustrates a generator at a cowshed for this purpose.
- Customers are informed of the need to install demand side surge protection and are given simple plug in surge diverters through various promotions.
- TLC promotes power factor improvement to all customers. Charges are based on kVA when metering is available to record this. As discussed in other sections TLC is annually surveying network power factor and using this data to reconcile actual values to its models.
- Detailed, accurate technical models are used for all development, customer and other projects to look for options. These models, as stated in other sections, include protection, harmonics and fault current features that allow more than just the impacts of power flow to be considered.
- Consideration of how automation and controls could be applied to minimise the asset investment for customer requests and network development.

FIGURE 5-7: GENERATOR BACKUP INSTALLED AT COWSHED

For example: Is it possible to use intelligent control systems to control and distribute load to maximise the utilisation of existing assets? (TLC has implemented several schemes. The most complex solution pushes a connection back and forward across the end of two feeders from different supply points, one of which has a distributed generation connection.)

- Information is made available from models to customers and retailers to encourage energy efficiency and minimise losses.
- Network security and reliability information is considered for all network and customer solutions. Often these factors influence the ability to use non-asset solutions.
- Encourage large industrials with high load demand to consider the alternative of installing a modular substation supplied from TLC's extensive 33 kV transmission network. This alleviates the capacity pressure on the 11 kV feeders and allows TLC to develop a currently constrained feeder further out in the network.
- Install capacitors to support the voltage. TLC is exploring this option and to date due to ripple signal interference has decided not to install permanent site. Instead TLC is developing a mobile capacitor bank that can be used to support the voltage when using generators on the network or in a back-feed situation where the voltage is dropping away.
- Mobile generators to support the network in fault situations or when supply is limited from the supply point, such has when MRP has its maintenance shutdowns at Whakamaru.

Once the best solution option is identified, TLC pursues this. Often considerable discussion must be held with the stakeholder parties and extensive financial analysis of the options completed. Medium to longer term solutions for a particular part of the network or site are considered and included in plans. For example: TLC has developed long term solutions for the ski fields. Each time modifications are made they progress the long term plan. The final network configuration will take about ten years to achieve.

TLC is committed to encouraging non-network solutions and sees this as a key pricing strategy, both for peak demand management and power factor correction. Customer incentives and education are seen as the most effective tools to encourage solutions at the load, thereby maximising the utilisation of existing assets and deferring investment. TLC believes that non-network solutions to minimise electricity costs (both lines and energy) for the end customer are a key to its overall operation strategy and giving customers long term value.

The forecasting section discusses TLC's understanding of the impact of demand billing and its encouragement of demand side management non-asset solutions. The analysis in this section illustrates the impact of these initiatives. The CAPEX estimates also illustrate the difficulty TLC would have funding upgrades as well as its renewal programmes without demand side management. At this time no dedicated cost benefit analysis of the savings that demand (or load) based charges are achieving has been done. However based on the savings that graphs 5-13 and 5-14 are showing and the effects of this as described in sections 5.3.6.4.2 and 5.3.6.4.3 extrapolated out into the network components it is estimated that over the planning period average deferred capital savings of $1 million per annum could be achieved. (Estimate based on calculations using the RAB value and comparing demand growth rates, with and without demand billing, using graph 5-10 and table 3-2 information/trends.)

5.5.2 Strategies Being Deployed to Promote Non-asset Solutions

5.5.2.1 Integration of Demand Side Management and Pricing Strategy

TLC encourages the implementation of policies and measures to reduce electricity demand, through the use of pricing strategy, high efficiency equipment and good operating practice. Over recent years, the demand on the TLC network has been growing at a faster rate than the energy transported. Peak demand is the defining factor for network upgrades and hence investment level. Controlling peak load is seen as an important initiative for TLC to minimise cumulative capacity network development and the escalation of customer charges.

TLC is the only lines company in New Zealand to introduce universal demand billing and to send separate bills to customers to ensure maximum impact of these pricing signals. This concept dates back to the 1950's when load control was extensively deployed in New Zealand. Demand and combined energy charges were passed down to large commercial customer level. The then technology, (i.e. demand measuring meters), involved complex mechanical devices and it was likely that this did not allow the concept to be applied at a lower level during these times. The arrival of electronic time of use meters at lower cost have changed this. A control period is a period commencing when a load control signal is sent to control demand and finishing when a further load control signal is sent to restore supply to the controlled demand.

Time of use meters to measure peak demands have started to be deployed and installation of these is being co-ordinated with relay and 2015 meter compliance requirements. Customers are charged for their peak demand during periods when load control is implemented. TLC's demand billing thereby encourages its customers to shift their peak usage to "off peak" periods. TLC has embarked on a programme to educate its customers on the billing structure and ways to reduce their electricity costs.

TLC's charging policy is based on components as outlined in other sections.

- A fixed charge based on the capacity made available. For a typical dwelling, this equates to 5 kVA or in dollar terms, approximately $250 p.a. for an urban dwelling after discount and exclusive of GST.
- A demand charge (about $200 to $250 per kVA).
- Charges for dedicated assets such as lines and transformers. This creates incentives for sharing assets and recuperates real costs for installation and maintenance.
- A customer service charge (for large industrial customers only).

Note: The capacity charge is also affected by customer density and is higher in rural areas. (These density bands reconcile with service level regions as discussed in Section 4.) Customers with other dedicated assets face additional charges associated with these assets. This structure allows customers the option of reducing capacity and demand.

5.5.2.1.1 Where demand meters are installed

FIGURE 5-8:"SWITCHIT" RELAY

Demand calculations are likely to be changed as a result of public consultation and recommendations provided by the Sapere review, from a single three hour period when TLC is load controlling to the average of six two hour periods when load controlling. There can be two periods in any single day recorded provided that there is at least five hours from the end of one control period to the beginning of the next.

In addition to fixed wired load control relays customers are using plug in relays for controlling appliances. Figure 5-8 show a "switchit" relay in use, the green light indicates that TLC is not load controlling the load control channel that the house is programmed to. The light is red on when the channel has been controlled and the appliance connected to the switch is disconnected. (The "switchits" have to be programmed to the same channel as the meter box relay to be effective, but are often a lower cost option that does not require wiring alterations.)

5.5.2.1.2 Where no demand meters are installed

Until half-hourly meters are installed in all installations a statistically derived formulae is used to calculate demand from uncontrolled energy meter readings. All load connected to the control relay is not included in this calculation as this will be disconnected during control periods. Reducing their total consumption will have a direct effect on the demand portion of their lines bill. Considerable savings can also be made by moving load onto the controlled load relay where this is installed as kWh consumption on the controlled meter is not included in the demand calculation.

5.5.2.1.3 Results

This structure has produced positive results amongst commercial customers where there is a high percentage of demand and time of use meters installed. This has been attributed to:

- A TLC initiative to hire consultants for commercial sector (mostly accommodation and tourism) to educate larger customers on how to reduce their demand and hence their costs.
- Commercial customers tending to be more aware of their costs than domestic customers and as a consequence understanding the ways to reduce charges.
- A push to get industrial customers to improve their operating power factor.
- PR campaigns and other customer awareness programmes.

TLC's programme of Customer Focus Groups and public meetings are beginning to show results through its domestic customers, and there is a greater understanding of load demand charging and why TLC has to build lines to take the maximum load, and that the infrastructure to carry that load has to be maintained to achieve the service levels that they, the customers, expect.

5.5.2.2 Generators Installed to Reduce Peak Demand

RAL has invested in a generator to bolster the supply in times of heavy use such as snow making on a winter's night on its Turoa ski field. Other large industrials that have critical load are encouraged to consider the same techniques.

Dairy farmers and small business are also encouraged to have a backup generator supply to enable them to carry on with their business in times of power outages.

TLC has two generators, the largest of which is 165 kVA, to allow it to supply areas that are disconnected by a fault or for maintenance where no back feed supply is available.

5.5.2.3 Distribution Network Capacitors

TLC, at this time, does not have any permanently mounted power factor correction capacitors connected to its network. Consistent with its demand side management and pricing strategy, TLC believes that the most effective and efficient place for power factor correction is at the customer's load. Hence intelligent billing is used in lieu of capacitors as the preferred means of power factor correction at this time.

Industrial customers are provided with free engineering advice as how to best control their power factor and loads. They are also charged based on kVA demand rather than kW, which gives further incentive to improve their power factor. Pricing has been set at a level where power factor correction pay backs are typically in the 2 to 5 year range.

TLC, however, recognises that there are locations where the future use of capacitors on the network will likely be the most cost effective way of maintaining voltage and meeting the Electricity Commission grid exit power factor requirements. Deployment at the present time is complicated by the old high frequency ripple injection plants and has been avoided. Rising harmonic levels may also add future complexity. As a shorter term solution the mobile active and reactive power unit concept is being developed.

5.5.2.4 Use of Intelligent Systems and Network Tuning

TLC has in place the base data systems required to move to an intelligent network. The base data in the existing systems are now at a level of detail, consistency and correctness where the data can be incorporated with other data sets. The strategy has been to use systems that have accessible data formats that can be integrated with other products.

TLC is investigating an upgrade of network analysis program to include the Smart Grid and/or Real Time modules that will interact with the SCADA data. Some of the benefits from introducing this system could be to provide more intelligent load shedding, switching, advanced monitoring, demand-side management and advanced forecasting features. The system is modular and therefore the purchase of packages will depend on cost-benefit analysis of each package.

This philosophy is integrally related to work to automate remote switches and a focus on flexibility for new projects. This automation and improving in the SCADA system is taking TLC closer to be able to start introducing a self-healing network. In many instances security of supply for a customer also equates to operational flexibility for TLC. There are cases where savings can be made via the optimisation of:

- Load distribution.
- Reactive power flow.
- Losses.
- Voltage (higher voltages leading to lower losses).
- Phase balance.

TLC is currently using its network analysis software to understand and tune network power flows to minimise losses and maximise the benefits of distributed generation and existing asset capabilities (e.g. regulators). Some of these optimisations can be achieved by an intelligent SCADA system. Some are implemented/encouraged in the Distribution Connection Code and pricing strategy. For example, it is possible to maximise distributed generation impacts and minimise the negative power factor effects by optimising generator control. One generator connected to the TLC network replaced controllers and indications are that technical network losses can be reduced by tuning these settings. Implementation of these savings is a multifaceted task and will require engineering time to determine where and how policy, investment or operational intervention is most effective.

5.5.2.5 Advanced (Smart) networks and TLC's positioning

Elements of advanced networks are available now and these technologies will have a cumulative effect as time goes on.

At this time the potential cumulative effect is a vision for TLC, and the key elements that we have in place to build on include a firm base of data, network analysis, direct based charging and other initiatives. The challenge is to bring these together in a planned way to provide improved service at a price customers are willing to pay. These initiatives must align with the strategic objective of being the best supplier of capacity to remote rural areas.

5.5.2.5.1 Definition of Advanced or Smart Networks

The definition that was adopted by an Electricity Networks Association working group is "The application of real time information, communication and emerging trends in electricity delivery to improve capacity utilisation, asset management practices and reliability on the modern network thereby optimising network investment to the benefit of all stakeholders."

This group concluded that the elements of an advanced network can be usefully grouped into three distinct layers. Figure 5-9 (on the following page) illustrates these layers and what they are.

The group went on to explore the cost benefits and concluded that "cost/benefit assessments indicate that the benefits of advanced networks substantially outweigh the cost at a national level". It is also considered that industry-wide policy settings may impede the deployment of advanced network technologies and identified a range of regulatory policies that prevent EDBs from deploying these technologies.

It is also recognised there is "no such thing as a representative EDB. Every EDB's advanced network investment would be different. The technology deployed is changing quickly and the cost established today will likely be out of date very quickly."

These latter points are very pertinent to TLC given that TLC is in a unique position given its direct charging strategies and remote rural environment.

Referring to the diagram in Figure 5-9 each of the layers are outlined and expanded on in the following sections.

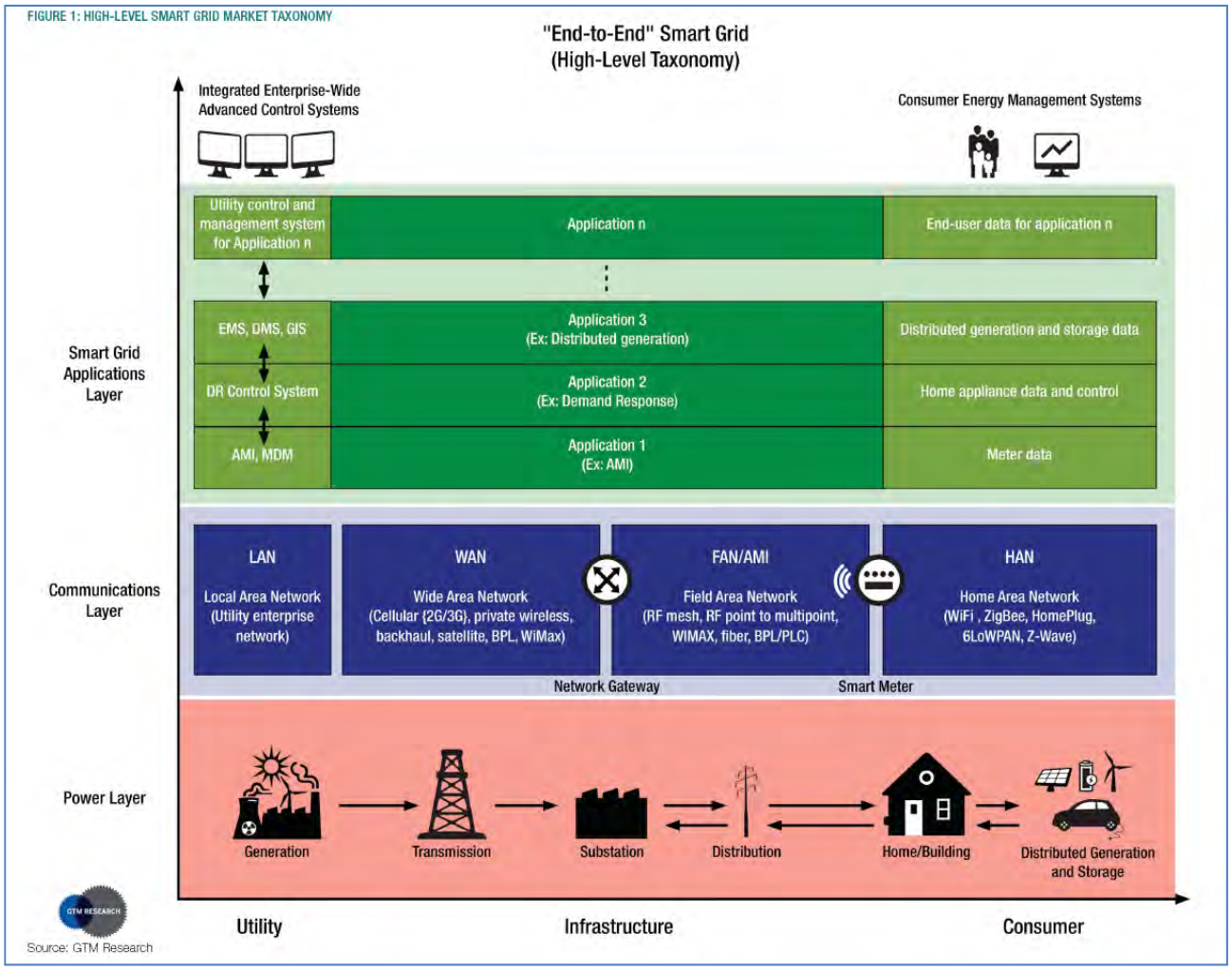


FIGURE 5-9: THREE DISTINCT LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

5.5.2.5.2 Smart Grid Application Layer

At the heart of the applications layer lays a central element of an advanced network. It is the ability to:

i. Monitor condition, consumption and injection across the network, preferably in real time.
ii. Control the controllable functions in the way load control does now. However, this will become more complex and may include such things as charging for electric cars and signalling to smart appliances in a future smarter world.
iii. Signal to customers the necessary information for them to make choices.
iv. Recover the value of investments.

The communications layer covers the technologies and developments that facilitate a smart transformation. It includes metering developments, communications developments and information management.

The physical world may change as a result of more distributed generation, electric vehicles and other storage devices. The basic system will still deliver energy to load centres from large generating stations but the net demand from the network will be more volatile. The key physical impact of these developments will be greater two-way electricity flows on the distribution network and transmission grid. By itself this feature would necessitate a more active network operation approach.

Elaborating on these layers and relating them back to the TLC network: The strategies/tools and development vision TLC currently has for these are summarised in the following Table 5-24.

CONTROL LAYER	
Item	**Comments**
Energy Market	TLC is in the network business, not the Energy Markets business. It is disconnected because of direct billing from retail. TLC has options going forward that can impact on the energy markets and distributed generators; specifically, there are parts of the network that are and can shift energy among supply points to benefit customers and generators. TLC is also concerned that energy markets can only focus on active power not reactive power. TLC's network transports about 66% active power and 33% reactive power; so the effects of reactive power are significant, i.e. it absorbs a lot of available capacity. TLC's direct charging approaches have been designed to focus on ensuring that the customers who require reactive power to be transported, and as such reduce the network capacity to transport active power, pay for the reactive power transport service.
Reserves Market	The relays TLC owns are all capable of operating in the reserves market. What it does not have is the resources to bid, control and administer this potential income stream. It also notes that there is uncertainty in this market and that the industry is likely to develop it further in the future. TLC will enter this market when it can provide firm cost benefit.
Ripple Receivers	TLC owns the present stock of which about half are operating on a less than optimal frequency. New plants are in place; however, the change out will have to be co-ordinated with a meter rollout given that the next generation meters and relays are integrated. The plan going forward is to split the channel allocations into feeder groupings so that TLC and Transpower network constraints can be individually signalled.
Load Management	The objective is to have more information and better use of this to make decisions. Specifically half hour metering, better price signalling ability to control more load; not withstanding some set time undertakings. The present load management controller takes inputs from supply points and compares these against one present target for a specific half hour. These targets have been broadly set to try and minimise Transpower interconnection charges and networks under constraint periods. Looking forward the load control calculator has to get more complex and capable of sending signals that are more localised as well as global. Over the next period TLC will further investigate the options for this and develop the most justifiable alternatives. This is an area that will get finer and more detailed as load management is controlled to an advanced network standard. The actual costs are not known at this time and as such are only included in forward estimates as contingencies under SCADA development. Forward load projections have assumed an on-going improvement in load factor where the demand growth is lagging energy growth by about 1%, as discussed in other sections. The costs and savings may be greater or less that these amounts.
SCADA Network Analysis, Asset Management, Technical Records, Billing and Accounting	TLC presently has SCADA, network analysis, asset management, technical records, billing and accounting packages/systems as described in other sections. A need for these systems going forward will be for them to have more visibility and control of all distributed assets to provide improved service, quality and security and be aware of revenues and costs. This will require data and application integration among SCADA, network analysis, asset management, technical records, billing and accounting packages. These systems will address all manner of things, the detail of which is currently being given consideration by TLC. The cost implications of these are unknown at this time; however, there are some allowances for this development in SCADA estimates.

CONTROL LAYER	
Item	**Comments**
Commercial and Domestic Applications	Power and information systems downstream of the meter will be needed by the customer. The communications layer will be key to these as will be the ability to draw information out of TLC systems via the internet and directly from the meter. The initial advanced meters being deployed by TLC do have a Zigbee communication system and in-premises displays tailored to the meter are planned to be made available. It is recognised that from a customer perspective this is key data/information and the options available will advance quickly. The architecture of these systems is currently being given consideration by TLC. The cost implications of these are unknown at this time and are not included in this Plan.

POWER LAYER	
Item	**Comments**
Distributed Generation	As outlined in other sections TLC already has significant distributed generation connected to its network and, as a consequence, it is well aware of the issues and has systems in place to accommodate these connections; however, significant tuning is required to take these forward and maximise the benefits. Connecting distributed generation to a network does introduce a number of complexities and more advanced control systems (tying back to the control layer) are required. (Many of these are discussed in other sections.) The present distributed generation requirements under Electricity Authority participation codes are limiting in terms of recovering the costs from generations for more advanced networks. At this time we have developed control systems for the existing network and the architecture has been built up around this. Further development of this architecture is currently being given consideration by TLC. The cost implications are unknown at this time; however a number of improvements will be covered by the existing allowances in SCADA and communications contingencies/allowances.
Automated: Self-healing Networks	TLC currently has not invested in automated self-healing networks. It has been focussing on getting the basic remote controlled equipment installed. Due to the radial nature of the network there are not as many potential options for the deployment of this technology as some other networks have. There are sites where the deployment may be useful and these will be researched and developed. As outlined in other sections it is a selection criteria for the equipment being purchased to have functions that will allow the deployment of some of these options. TLC's engineering structure is currently being adjusted to provide a level of additional resource to be able to carry out some additional research in this area. At this time there are no specific allowances in favour of estimates for the deployment of this technology; however, some of the contingency amounts in the communications and SCADA areas will likely go some way to achieving the "low hanging fruit" in this activity.
Reactive Power and Voltage Control	Over the last nine years TLC has been busy deploying modern technology assets (see Section 3) to ensure compliance with the electricity regulations. Similarly in Section 5 there are a number of deployments planned going forward. The recent upgrade of the injection plants in the Northern area has also meant that the deployment of capacitors is now an option. Also, as outlined in other sections, TLC is sending a message to customers via its charging to minimise reactive power flows. The intent is to increase the level of network tuning going forward. Forward expenditure predictions have been increased to cover off a level of increased engineering to research and develop more advanced schemes. The additional hardware and software investment is not included in forward estimates at this time.

POWER LAYER	
Item	**Comments**
Capacity	There are a number of things TLC could do to extract more capacity out of existing assets, particularly given the capability of things such as modern regulators, better information systems and reactive power flow initiatives. The implementation of these will likely be on an area-by-area basis. Such initiatives will require mostly technical labour type input plus some sensors and more advanced modelling.
Asset Management Information	The use of more advanced asset management information and the inter-relationships associated with this are perhaps part of the control layer but they also have a direct impact on the management of the power layer. An important part of running the power layer in a more advanced manner is to have individual, sectored combined asset data and connectivity models from supply points to end customers. TLC has in place as asset management system to do this; however, as time goes on more and more requests will be made of these systems and the information they contain will be integrated. It is likely that these systems will become critical for reporting and the needs for continuous improvements for customer service associated with the power layer. TLC's present business planning allows for investment in these systems each year. At present the system is continuing to be developed and the need to complete a more visionary plan for the asset management system in conjunction with other systems is recognised.
Inspections and Testing	The inspection and testing of the power layer is critical for controlling the hazards and risks associated with its operation. Advanced networks will have some capability to remotely and automatically carry out a level of inspections, tests and measurements to ensure control of hazards, quality, security and risks. Advanced networks will also require a range of different types of tests and inspections as compared to existing networks. At this time we are unsure of the details and estimates so these items have not been included in the Plan.
Load Control Signalling	Advanced networks will likely start off utilising the legacy injection and signalling equipment, however going forward this will be substantially expanded and or replaced/supplemented with other signalling systems. At this time we have only assumed a continuation of the existing injection systems in forward expenditure estimates.
Fault Data from Field Services and Analysis of this to Automatically Dispatch to the Likely Fault Site	It will be possible with an advanced network to combine SCADA and network information to send staff to the likely site where a fault has occurred or is likely to occur. This capability has been recognised by TLC; however, at this time equipment and system detail needed to be able to implement this has not been researched or set up.
Reactive Power, Load Factor and Losses (Environmental Effects Inherent in a Power System)	With an advanced network some of the technical information that will become available in real time that is associated with operating efficiency and environmental effects includes reactive power flows, load factor and losses. How this information is applied is only very visionary at this time and will require considerably more research. No cost implications or benefits have been considered.

POWER LAYER	
Item	**Comments**
Transmission, Sub-transmission and Substation Interfaces	Advanced networks will make use of a lot more data and information from transmission, sub-transmission and substation interfaces. At this time no research has been done on the potential and how this information may be used.
Security	With the increasing value of copper, thefts and interference with power layer equipment is becoming more common. Advanced networks will likely have features that will increase security and related monitoring. This area is still to be researched.

COMMUNICATIONS LAYER	
Item	**Comments**
Ripple Signal	Ripple signal has the advantage that it reliably can send signals to large numbers of customers quickly and efficiently without involving a secondary communication system. This unique feature means that it has significant advantage. It cannot be used for 2-way network communication and as a consequence, given the hilly nature of the TLC network, it has been assumed it will be around for some time.
Voice Radio, Data Radio, Internet Protocols, Mesh Radio	The way the various communication mediums will be needed and develop as part of an advanced network is unknown at this time.

TABLE 5-24: STRATEGIES, TOOLS AND DEVELOPMENT VISIONS TLC HAS FOR THE LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

5.5.2.6 Large Industrial Customers Encouraged to Install Modular Substations

TLC has an extensive 33 kV transmission network to supply the widely scattered zone substations. If a large industrial approaches TLC with a proposed load increase the possibility of installing a modular substation to supply the installation is investigated. This increases both security and quality of supply for the customer.

In 2006, Hautu prison was the first large customer to which the modular substation principle was applied. In this case a 33/11 kV substation was installed by teeing in to an existing 33 kV line and tying into the existing 11 kV feed to the prison. As such the prison is no longer dependent on a rural feeder that would otherwise have to be upgraded to meet their demand and reliability expectations. This supply, can however be used as backup (at a reduced load). As the 33 and 11 kV lines come from different points of supply, redundancy is achieved. The substation was customer funded, and lower cost than an 11 kV upgrade.

The modular nature of the substation means that, if it becomes redundant, it can simply be moved to the next desirable location. The success of this solution is obviously dependent on location and capacity of surrounding circuits but has, in at least one case, met the needs of both the customer and TLC at a reasonable cost.

TLC also has large industrial customers in the northern area where planning is in place to provide them with a modular zone substation supplying the industrial directly from the 33 kV network.

5.5.2.7 Ripple Control and Load Shedding

5.5.2.7.1 Peak Demand Load Shedding

TLC uses its ripple system to avoid RCPD peaks and reduce/signal network constraints. In 2010 the renewal of the old ripple system in the northern area operating on 725 Hz to a new system operating on 317 Hz began. The progressive replacement of customer relays over the next 3-5 years will see a significant improvement in the control TLC has over load at peak times.

As mentioned earlier, TLC is evaluating a package provided in conjunction with the network analysis program and will need to justify the initial cost against the proposed savings in reduced GXP costs, power factor penalties, MW and MVAr losses, and avoidance of network upgrades.

A key to further enhancing demand side management will be to implement systems for load control at feeder level and below. This will require intelligent load control systems.

5.5.2.7.2 Under Frequency Load Shedding

TLC has Automatic Under Frequency Load Shedding (AUFLS) relays which is a requirement from the Electricity Commission to ensure that the national grid does not experience total system instability and fail. TLC has devised a system where, if an under frequency event should occur, blocks of load are disconnected from the system.

5.5.2.8 Alternative Supplies for Remote Rural Areas

TLC has investigated and will continue to investigate the use of alternative supplies for remote rural areas. Work to date (that is supported by independent studies) shows that most customers prefer grid supply for sites that are permanently lived in or where dairying is taking place.

Alternative technologies are often used to supplement supplies. For example dairy farms are often established in areas where there is only a single phase supply. Often these farms connect to the single phase supply for vat cooling and install generators for the dairy milking times. Similarly woolsheds are often supplied by generators.

The reality is that farming today is a complex and busy business. Farmers need to focus on this, not running alternative electricity supplies. As a consequence of this most want a reliable grid supply to support their activities.

5.5.2.9 Solar Panels and Domestic Wind Turbines

While TLC encourages customers to support their own power usage through the installation of photoelectric solar panels, solar hot water boosters and small wind turbines, TLC at this time does not have sufficient resources to assist in the development of these types of small business or domestic power supplies. TLC encourages customers to use the technical advisors associated with the distributors of these products.

However, customers who do install alternative generation and reduce their peaks do benefit from lower network fees under the Demand Billing system. A number of customers have these devices connected.

5.5.2.10 Surge Arrestors and Surge Suppression

In order to minimise damage to customers' equipment connected to the network, surge arrestors are installed on the network. In addition to this a TLC promotion was run to issue vouchers for surge protectors to customers. Surge protectors are also given out by faults staff, lines inspectors and as part of promotions.

5.5.2.11 Network Non-technical Losses

TLC has evidence of a significant variation between actual losses and losses derived by retailers from the difference between metering data at GXPs and that used for billing at the customer ICPs. The technical losses have been calculated by modelling and make up about 55% of the losses. To get accurate data on the remaining 45% (approx.), is very difficult, with the non-technical losses being caused by metering, meter reading and retailer billing errors.

Losses are funded by customers when retailers add these costs back into energy rates. Improving the accuracy of billing does involve working with retailers to minimise non-technical losses. TLC has worked with its test house and found that about 20% of meter exchanges lead to errors in meter data/readings. For example there have been instances where meter readers have substituted reactive power for active power readings. Blown or disconnected VTs and reverse connected CTs also frequently lead to metering errors – usually underestimation of consumed kWh.

TLC believes the best solution for these kinds of errors is to improve metering technology. Remote meter reading will not be simple in the King Country due to geographic communication difficulties. However, deployment of improved metering (for example handheld units that read and record data automatically) as part of the 2015 compliance and TLC's demand metering needs will likely significantly reduce meter reading error.

5.5.2.12 Potential for Distributed Generation or other non-network solutions to address network problems or constraints

Distributed generation will tend to reduce grid exit power factors. Distributed generation connected to appropriate places in the network along with good load control systems that promote demand side management will prolong the time before present assets need upgrading. The strategies for various parts of the network are discussed in the following sections.

5.5.2.13 Impact on Sub-transmission Network of Distributed Generation

5.5.2.13.1 Grid Exits

Additional distributed generation into Hangatiki will have an impact on connection costs. The present transformers do not have n-1 capacity and are heavily loaded during peak demand periods without the availability of distributed generation. The problem with currently connected generation is that it is all run of the river and, as such, is rain dependent and is not necessarily available during periods of peak load.

The possible connection of wind farms at Taharoa may overcome some of the present constraints at Hangatiki. TLC is currently working with Transpower to increase the rating of the present transformers by putting fans on them and is hopeful that customers' reactions to demand billing will buy time to allow the full impact of the wind farms and other distributed generation to be monitored. It is hoped that these combined effects will increase the lifespan of the present Hangatiki supply.

It should be noted that the connection of distributed generation will likely mean that Hangatiki transformers and protection may have to be upgraded to allow for injection as well as off take. Injection will also have an effect on the 110 kV Waikato network and the amount of run back /reactive power generation needed from the major generators on this network, particularly the Arapuni hydro site.

A proposal by Waipa Networks to take supply out of Hangatiki may also further complicate the issue. TLC will likely oppose any implications of this initiative that will increase connection/interconnection costs and/or place constraints on operating flexibility or other factors at this site.

5.5.2.13.2 33 kV Lines

Distributed generation and demand side management has the potential to ease the loading on the Whakamaru 33 kV, Taumarunui to Ongarue 33 kV and Te Waireka/Te Kawa 33 kV lines. Distributed generation proposals have the potential to cause upgrades of Taharoa, Te Kuiti and Mahoenui 33 kV lines.

5.5.2.13.3 Zone Substations

Distributed generation and demand side management have the potential to ease the loading on the following zone substations and their transformers and prolong the period before an upgrade is required:

- Marotiri
- Kuratau
- Tawhai
- Hangatiki
- Gadsby Road
- Maraetai
- Borough
- Waitete
- Atiamuri.

The following sites may need upgrading as a result of potential connected distributed generation:

- National Park

5.5.2.13.4 Distribution Feeders

Distributed generation can assist with supporting loadings on distribution feeders. However, during periods of light load on a relatively long and high impedance system it can push voltages high. Inductors or absorption of reactive power can be used to control this, but these actions can have a detrimental effect on overall network power factors and system stability.

5.5.2.14 Demand Side Management Summary

TLC uses as many approaches as possible to ensure customers' capacity and cost expectations are met. These tools include the construction of capacity, generation and demand side management initiatives.

Due to the remote nature of the TLC network and that it is sparely populated, the cost of capacity construction can be high and often customers' ability to pay is limited. As a consequence of this, TLC is leading the way nationally in its charges that are designed to promote demand side management. It is acknowledged however, that demand control was used extensively in the 1950's and early 1960's. At that time though the technology such as electronic half hourly meters was not available to make this concept accessible to all customers. This technology is now possible.

Customers are encouraged to update their meters to a demand meter that allows the customer to use electricity in off peak times and gain the benefit in lower charges. TLC plans to roll out demand meters to all customers over time; however, the initial focus will be on areas such as Ohakune and other areas where there are difficulties with the profiling methodologies due to the high proportion of holiday load.

TLC's forward asset management plans are relying heavily on demand side management to control demand and alleviate the need for investment in development while larger renewal programmes are in place. The use of capacitors and generators are to postpone the need to upgrade the network and TLC has installed (and is planning more) voltage regulators on its feeders to push the ageing and small volume feeders to their limits, however, the forward expenditure for TLC will need to include conductor and system upgrades to manage the system growth in the long term.

5.6 Analysis of Network Development Options Available and Details of the Decisions made to satisfy and meet Target Levels of Service.

The solutions listed below are after consideration of non-asset solutions including the gains made by demand billing and distributed generation.

5.6.1 Network Development Options Available and Details of Decisions Made For Solving the Issues

Earlier sections details the constraints experienced on TLC's Network. The following tables summarise the development option decisions, cost estimates and timing of the projects selected for the next 15 year planning period.

Notes:

- The highlighted row indicates the selected option.
- 11 kV Development tables only show option chosen due to the large amount of data.
- The values are at today's value without inflation.
- Voltage regulators are listed as a separate table for development work for voltage constraints (Section 5.6.1.8) as are conductor upgrades (Section 5.6.1.9).
- Substation Asset replacements and renewals are included in this section for ease of presenting the information in one place to make it easier for project managers to understand. The renewals have been coded to the appropriate Commerce Commission code categories.
- Line Asset replacements and renewals are listed in Section 6.

5.6.1.1 The Whole Network

Table 5-25 lists the development work planned that will be advantageous to TLC's whole network by mitigating the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

WHOLE NETWORK (Common Mobile Assets)			
Constraint	**Option**	**Description**	**Year and Cost Estimate**
Reliability and Security	Network Option	Build a network that has n-1 security throughout.	
	Non Network Option	Semi- Mobile containerised 2.5 MVA substation.	450k in year 4
	Do Nothing	Do nothing and increase the length of customer outages or hire in generators to support the load which increases the overall cost of work.	
Reliability and Security	Network Option	Install n-1 at all substations.	
	Non Network Option	Have a mobile generator to support loads. Upgrade existing generator.	169k in year 14
	Do Nothing	Do nothing and increase the length of customer outages.	
Reliability and Security	Network Option	Construct a backup injection plant at each site.	
	Non Network Option	Have a semi mobile injection plant that can be relocated. Reuse the load control plant that is removed from National Park.	68k in year 3
	Do Nothing	Unable to control the load in times of constraint.	

TABLE 5-25: PROPOSED DEVELOPMENT WORK THAT BENEFITS THE WHOLE NETWORK

5.6.1.2 Assets Connected to Hangatiki Point of Supply

Figure 5-10 indicates the area supplied from the Hangatiki Point of supply and the Feeders' geographical location. Figure 5-11 and Figure 5-12 indicates the Supply Point's relationship to the Zone Substations and downstream Feeders.

Table 5-26 to Table 5-28 lists the development work planned for assets connected to the Hangatiki point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

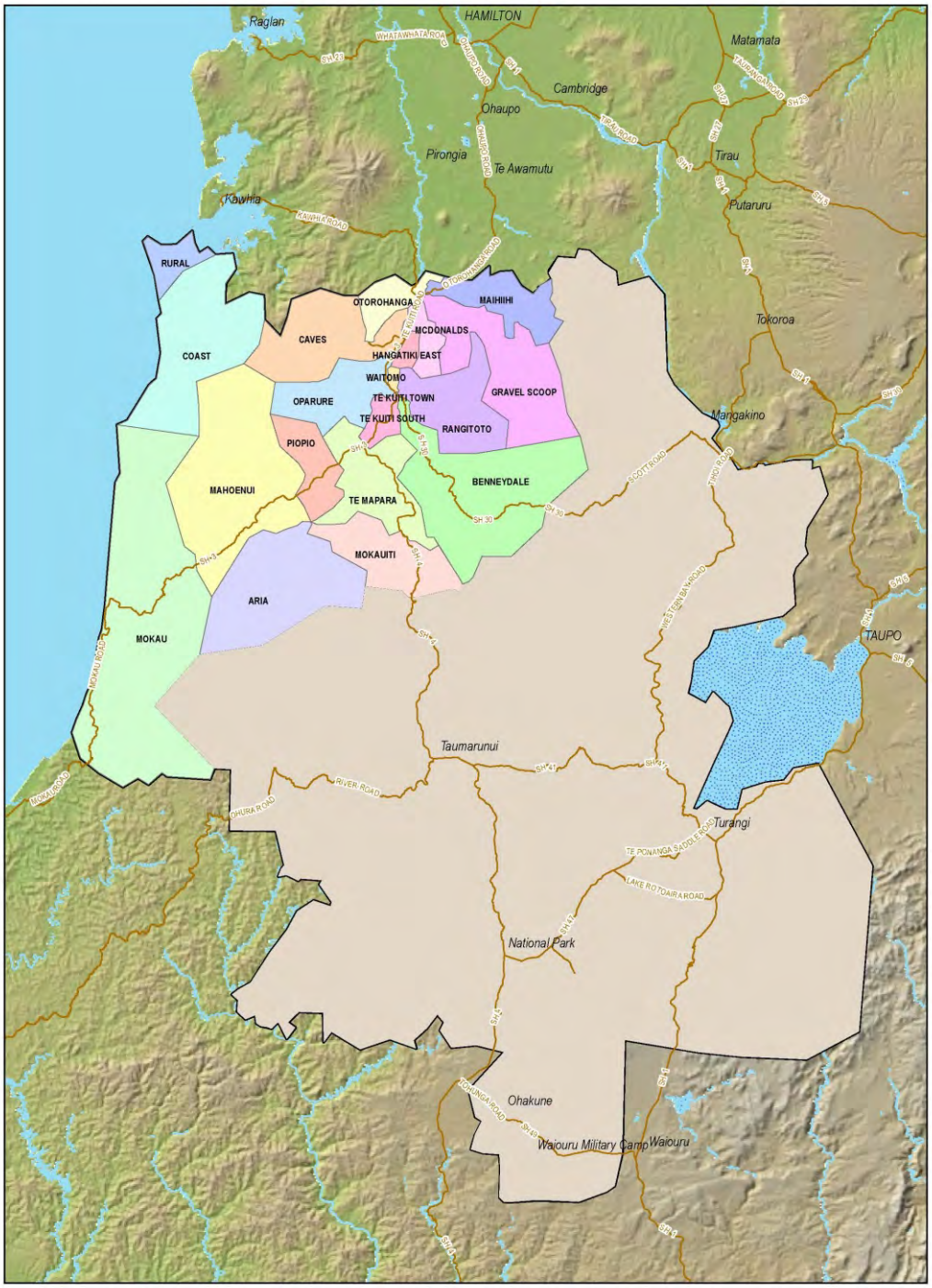


FIGURE 5-10: HANGATIKI SUPPLY AREA AND FEEDER LOCATIONS

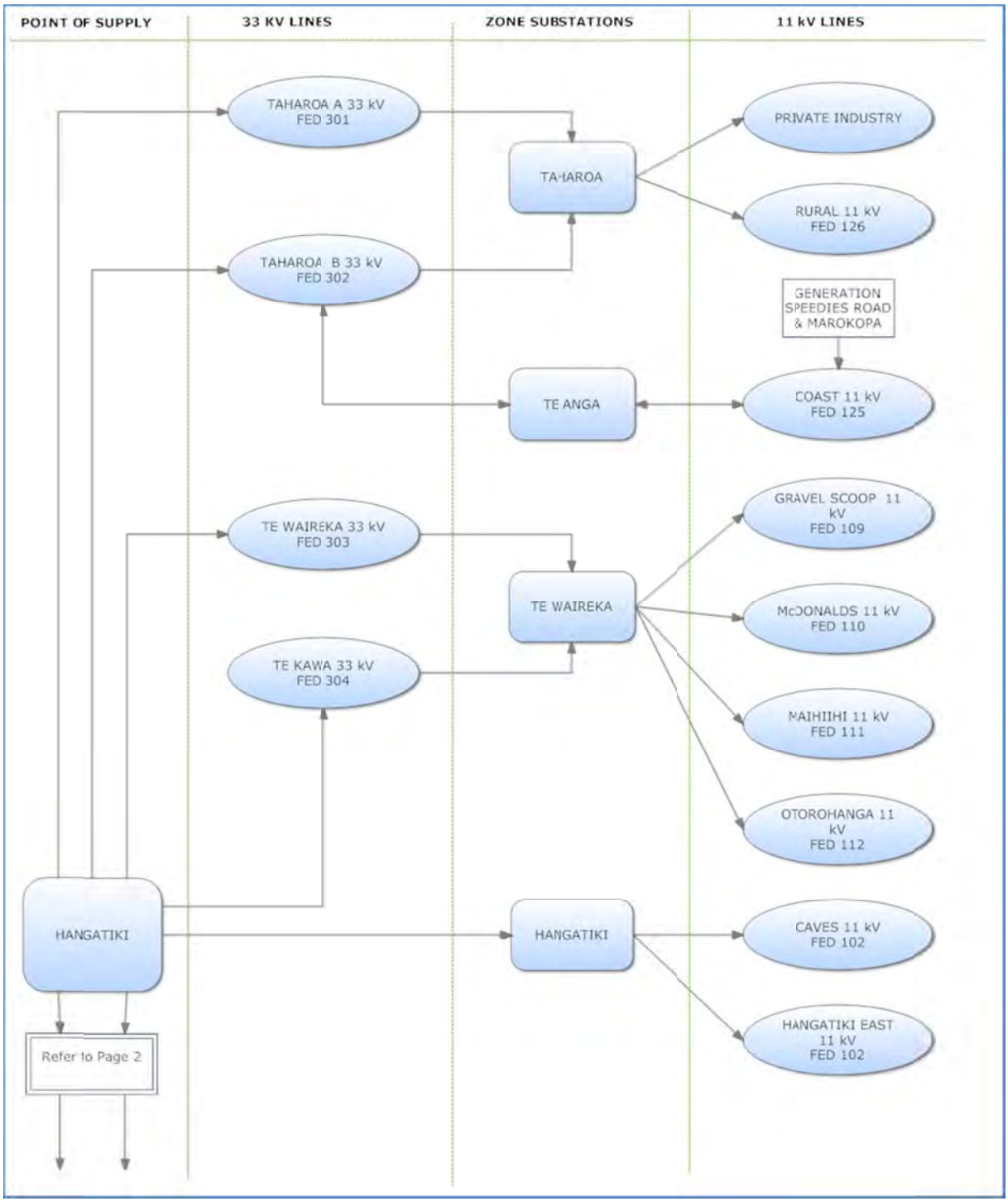


FIGURE 5-11: CONNECTION DIAGRAM OF ASSETS CONNECTED TO HANGATIKI POS (PAGE 1)

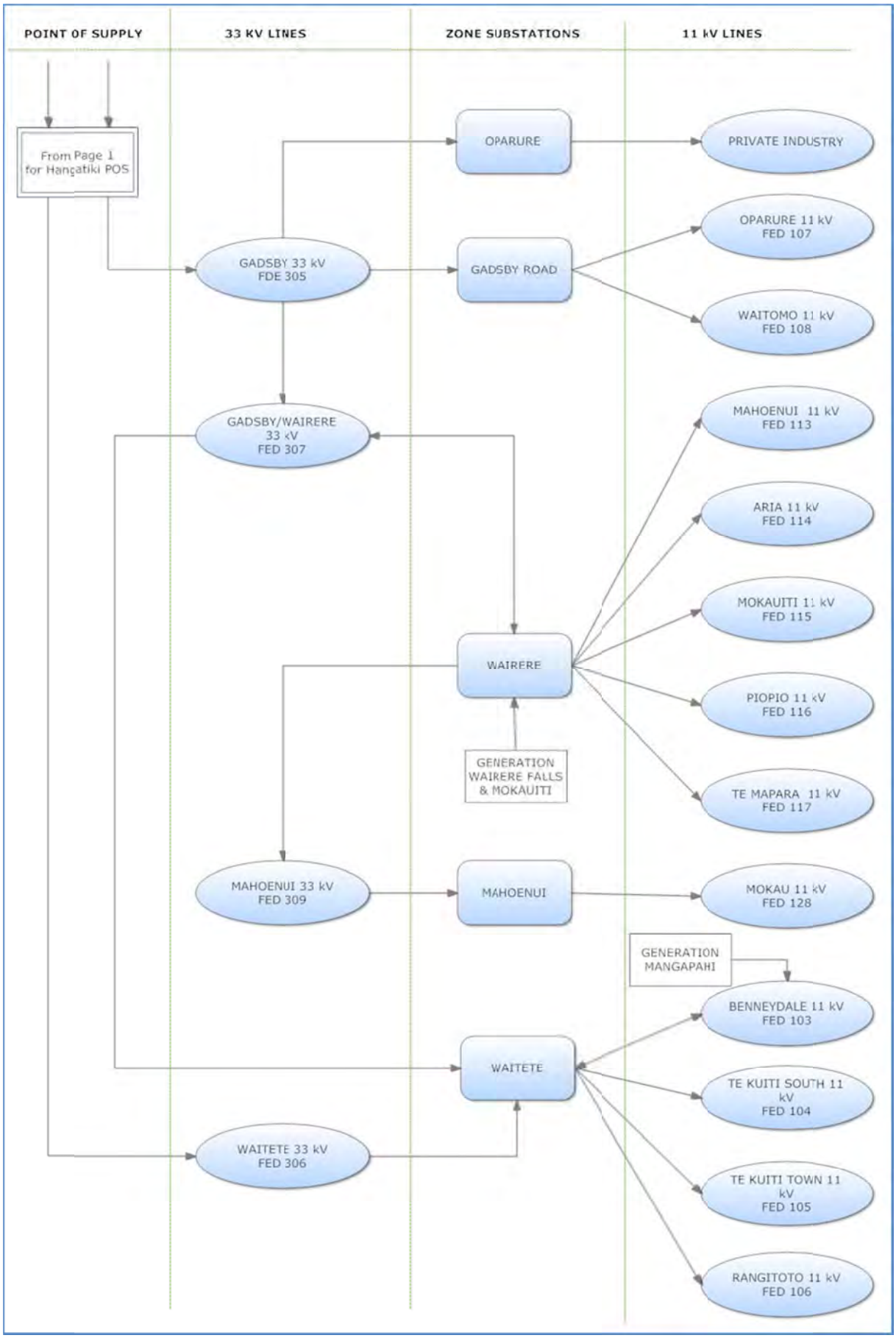


FIGURE 5-12: CONNECTION DIAGRAM OF ASSETS CONNECTED TO HANGATIKI POS (PAGE 2)

HANGATIKI POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TAHAROA B	Hazardous Asset Renewals	Network Option	Renew and remove hazardous equipment. Customer has not made a decision: Coincides with confirmed upgrading of site. Cost to bring reliability to expectations of large 24/7 plant.	112k in yr4	Hazard and Reliability control of existing equipment.
		Non Network Option	Industrial customer to install generators for reliability and TLC customers would experience longer outage times. Wait for DG (distributed generation).		
		Do Nothing	Down grade reliability and only complete emergency repairs		
TAHAROA A	Customer Connection	Network Option	Upgrade line to higher transmission voltage and capacity (for distributed generation connection).	337k in yr7 337k in yr8	Customer will require a line upgrade to a higher voltage and landowner access requirements. (This expenditure may be directly funded by the customer.)
		Non Network Option	Connect to line with reduced capacity. (Customers have selected capacity greater than the lines capacity).		
		Do Nothing	Connect to line and affect other customers. Operate assets beyond their maximum limits.		
GADSBY/WAIRERE	Customer Connection	Network Option	Allow for full output of proposed schemes. Install additional Regulators at Wairere to pull down voltage.	281k in yr13	If generator gets resource consent they will not want to restrict output.
		Non Network Option	Restrict generation injection with proposed schemes.		
		Do Nothing	If the proposed generation goes ahead then the current on these lines will be over the current capacity of the existing lines.		

TABLE 5-26: PLANNED WORK FOR 33 KV LINES CONNECTED TO HANGATIKI POS

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TAHAROA	Customer Connection	Network Option	Upgrade to customers' requirements and specifications. Funded through on-going charges to industrial customers.	788k in yr4 56k in yr5	To meet customer expectations.
		Non Network Option	None available.		
		Do Nothing	Industrial customers will not be able to expand.		
TE WAIREKA	Cumulative Capacity	Network Option 1	Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1,463k in yr15	Lowest cost solution and does not increase the already high fault levels at Te Waireka Road.
		Network Option 2	Upgrade lines from Te Waireka substation.		
		Non Network Option	Install generators or capacitors to lift the voltage. Will not achieve the required capacity.		
		Do Nothing	Restrict loading and experience possible voltage level breaches. Unacceptable to customers.		
TE WAIREKA	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Modify and install oil bunding, oil separation and earthquake restraints.	28k in yr1	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
HANGATIKI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr5	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
HANGATIKI	Customer Connection	Network Option	Install more capacity.		
		Non Network Option 1	Diversify and encourage industrials downstream to install 33/11kV modular substations on their sites. Oyma container sub. Customer funds costs through on-going charges.	394k in yr10	Cost, reliability improvements and fault current control.
		Non Network Option 2	Transfer load to another site. However this is not possible at this site.		
		Do Nothing	Industrial customers will not be able to expand. Customer choice.		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
GADSBY ROAD	Environmental	Network Option 1	Rebuild site		
		Network Option 2	Modify existing site by installing better earthquake restraints.	34k in yr11	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages during an earthquake.		
WAITETE	Customer Connection	Network Option	Install another transformer at Waitete.		
		Non Network Option	Install modular substation at industrial sites, Funded through on-going charges to industrial customers.	394k in yr6	More modular and cost is Customer focused.
		Do Nothing	Industrial customers will not be able to expand.		
WAITETE	Environmental	Network Option 1	Alter configuration or location.		
		Network Option 2	Modify and install oil bunding, oil separation and earthquake restraints.	28k in yr1	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
WAITETE	Hazardous Asset Renewals	Network Option 1	Move or alter substation.		
		Network Option 2	Replace fence.	68k in yr4	Need a secure area for substation. Most cost effective.
		Non Network Option	None available.		
		Do Nothing	Fence deterioration could cause a security breach.		
WAIRERE	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformers (T2).	90k in yr9	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security
		Non Network Option	None available.		
		Do Nothing	Leave as it is at present. Transformer could fail if not refurbished.		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
WAIRERE	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformers (T1).	90k in yr7	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.
		Non Network Option	None available.		
		Do Nothing	Transformer could fail if not refurbished.		
WAIRERE	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr7	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
WAIRERE	Hazardous Asset Renewals	Network Option	Renew switchgear and improve protection schemes (33 kV).	338k in yr9	Protection schemes need updating due to the separate owners of the generation.
		Non Network Option	None available.		
		Do Nothing	Leave site as is and risk network security.		
OPARURE	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install bunding, oil separation and earthquake restraints.	45k in yr6	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible contamination due to oil leakages.		
MAHOENUI	Hazardous Asset Renewals	Network Option	Replace 11 kV Circuit breaker with modern equipment and increase the functionality of the breaker. Risk to reliability and security and protection not operating.	68k in yr1	Circuit breaker and protection are getting old and need maintenance renewal to be reliable.
		Non Network Option	None available.		
		Do Nothing	Run breaker until it fails, then have time delays in replacing it, while sourcing equipment.		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
MAHOENUI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Increase the height of the oil bund and install oil separation.	17k in yr12	Required for environment protection.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
MAHOENUI	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformer.	56k in yr12	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.
		Non Network Option	None available.		
		Do Nothing	Transformer could fail if not refurbished.		
MAHOENUI	Hazardous Asset Renewals	Network Option	Replace fault thrower with CB 33 kV.	68k in yr14	Fault throwers are unreliable and cause damage to other equipment. They have to be manually reset.
		Non Network Option	None available.		
		Do Nothing	Could decrease reliability.		

TABLE 5-27: PLANNED WORK FOR SUBSTATIONS CONNECTED TO HANGATIKI POS

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
BENNEYDALE	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T2506	Rebuild with a standard single pole structure.	28k in yr5
		Ground Mount Transformers: Condition & Hazards	T2598	3-Phase 500kVA.	45k in yr11
COAST	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T547 T640	3-Phase 300kVA. 3-Phase 200kVA.	45k in yr6 45k in yr8
CAVES	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1185	Construct to TLC's current Network Standards.	45k in yr10
GRAVEL SCOOP	Reliability	Switches (Reliability Improvement)	304	Automate to TLC's current Network Standards.	28k in yr11
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1007	3-Phase 300kVA.	56k in yr9
HANGATIKI EAST	Reliability	Switches (Reliability Improvement)	361 336	Automate to TLC's current Network Standards.	23k in yr8 39k in yr7
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T381	Replace the I tank or front access transformer. Use refurbished transformer if available.	45k in yr4
MAHOENUI	Reliability	Switches (Reliability Improvement)	1343 1512	Automate to TLC's current Network Standards.	45k in yr8 45k in yr9
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1453 T1692 T1865 T2520	Construct to TLC's current Network Standards.	39k in yr4 39k in yr7 6k in yr4 39k in yr4
MAIHIIHI	Reliability	Switches (Reliability Improvement)	127	Automate to TLC's current Network Standards.	45k in yr8
MCDONALDS	Reliability	Switches (Reliability Improvement)	320 387 328	Automate to TLC's current Network Standards.	23k in yr6 34k in yr5 23k in yr5

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
MOKAU	Reliability	Switches (Reliability Improvement)	1626	Automate to TLC's current Network Standards.	45k in yr14
	Cumulative Capacity	Feeder Development	FED 128	Advance the 33 kV line as the load grows. Mokau Generator: Add remotely controlled diesel or gas injection for holiday periods and during shutdown interruptions.	675k in yr14 338k in yr8
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T2140 T2154 T2155	T2140 3-Phase 100kVA. T2154 to change 11kV cable and DDO's. T2155 3-Phase 500kVA.	45k in yr8 45k in yr8 45k in yr8
		Low and Hazardous Two Pole Structures	T2153 T2177 T2194 T2208	T2153- Rebuild restructure with standard single pole design. T2177 Construct to TLC's current Network Standards. T2194 Construct to TLC's current Network Standards. T2208- Rebuilt structure with standard single pole design.	23k in yr3 45k in yr6 6k in yr7 45k in yr7
OTOROHANGA	Reliability	Switches (Reliability Improvement)	316 288 645 308	Automate to TLC's current Network Standards.	45k in yr12 28k in yr4 11k in yr3 11k in yr3
		Feeder Development	FED 112	LV Link T554 toilet block link to adjacent Transformers.	113k in yr6
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1174 T1552 T170 T699 T557	T1174 3-Phase 200kVA. T1552 3-Phase 300kVA. T170 3-Phase 200kVA. T699 3-Phase 300kVA. T557 Install TX with RTE.	45k in yr15 56k in yr12 45k in yr10 45k in yr6 45k in yr8

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
OPARURE	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1043 T457 T663 T9	T1043 3-Phase 500kVA. T457 Install a front access transformer 300kVA with I blade RTE switch. T663 Replace with refurbished I tank transformer. T9 3-Phase 250kVA.	56k in yr10 45k in yr5 45k in yr3 45k in yr7
RANGITOTO	Reliability	Switches (Reliability Improvement)	224	Automate to TLC's current Network Standards.	45k in yr13
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T464	Replace with a refurbished I tank. Check loading and size of transformer.	45k in yr5
RURAL	Reliability	Ground Mount Transformers: Condition & Hazards	T1367 T1390 T1559	T1367 3-Phase 100kVA. T1390 3-Phase 200kVA. T1559 3-Phase 100kVA.	45k in yr10 45k in yr9 45k in yr11
TE KUITI SOUTH	Reliability	Switches (Reliability Improvement)	730 242	Automate to TLC's current Network Standards.	23k in yr2 23k in yr14
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T10 T1447	T10 3-Phase 300KkVA. T1447 3-Phase 300kVA.	56k in yr9 34k in yr14
		Low and Hazardous Two Pole Structures	T478 T559	Construct to TLC's current Network Standards.	56k in yr6 56k in yr3
TE MAPARA	Reliability	Switches (Reliability Improvement)	1316	Automate to TLC's current Network Standards.	23k in yr2
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1777 T1829	Construct to TLC's current Network Standards.	45k in yr4 8k in yr5
WAITOMO	Reliability	Switches (Reliability Improvement)	182	Automate to TLC's current Network Standards.	23k in yr10
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1003 T406	T1003 3-Phase 200kVA. T406 3-Phase 200kVA.	45k in yr15 45k in yr4

TABLE 5-28: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO HANGATIKI POS

5.6.1.3 Assets connected to Whakamaru & Mokai Geothermal Points of Supply

Figure 5-13 indicates the area supplied from the Whakamaru and Mokai Geothermal Points of supply and the connected feeders geographical location. Figure 5-14 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 29 to Table 32 list the development work planned for assets connected to the points of supply in the Whakamaru / Mokai areas to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

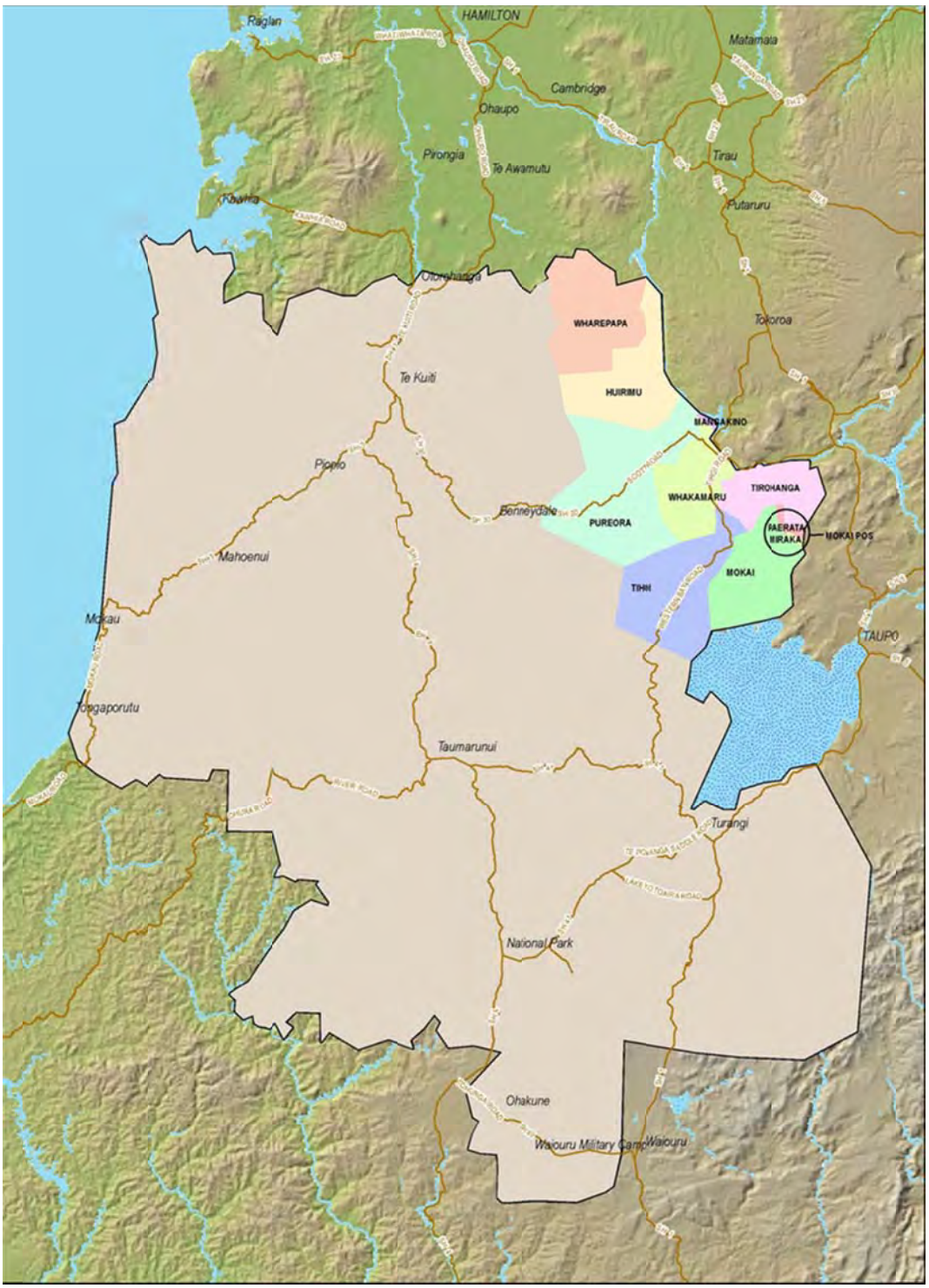


FIGURE 5-13: WHAKAMARU & MOKAI GEOTHERMAL SUPPLY AREAS AND FEEDER LOCATIONS

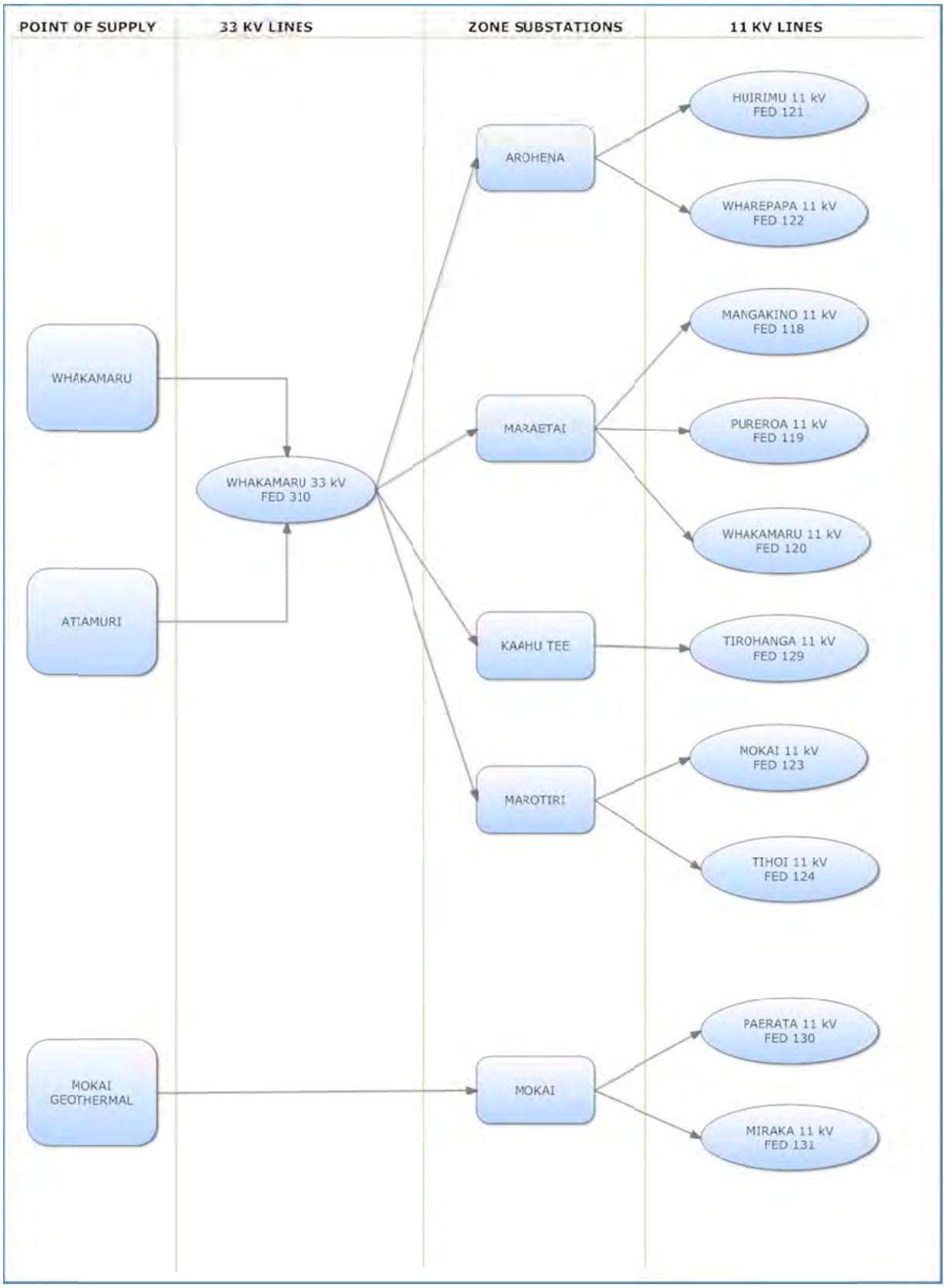


FIGURE 5-14: CONNECTION DIAGRAM OF ASSETS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL SUPPLY AREAS AND FEEDER LOCATIONS

WHAKAMARU & MOKAI POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
ATIAMURI	Cumulative Capacity	Network Option 1	Increase transformer capacity		
		Network Option 2	Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information Year 2 revisit the need for fans.	11k in yr1 34k in yr2	Will delay higher cost options.
		Non Network Option	None available.		
		Do Nothing	Overheat transformer and reduce its life. Limited ability to meet customer's capacity expectations.		
ATIAMURI	Cumulative Capacity	Network Option 1	Upgrade transformer at POS. If the transformer at Atiamuri is upgraded the conductor size is not great enough to transport the capacity so a line upgrade would be required.		
		Network Option 2	Supply from Transpower at Whakamaru on the 220 kV or Mokai 110 kV supply connection at Whakamaru.	1,126k in yr11	This is the most cost effective solution.
		Non Network Option	Uses generators and capacitors to back up load at peak loading times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MOKAI	Cumulative Capacity	Network Option 1	Take a supply from Transpower proposed substation near Mokai. This will be expensive.		
		Network Option 2	Increase capacity taken from Mokai Geothermal.	394k in yr15	Most cost effective.
		Non Network Option	None available.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MOKAI	Cumulative Capacity	Network Option	Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	394k in yr7	This is the most cost effective.
		Non Network Option	Run without load control, use some other technology.		
		Do Nothing	Unable to control load in area.		

TABLE 5-29: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
MOKAI	Customer Connection	Network Option	Rebuild a new 33 kV line to a new modular substation. Line interconnects with 33 kV line to Marotiri and will be built on Tuaropaki Trust Land. Substation to be located on Tirohanga road near Pumps. Work in conjunction with 11 kV conductor upgrade on Tirohanga Rd.	721k in yr2	Customer requires for improved reliability.
		Non Network Option	Use generator at times of capacity constraint or during faults.		
		Do Nothing	Customer will not have the security that they require.		
WHAKAMARU	Cumulative Capacity	Network Option	Regulators at Atiamuri to increase voltage. 33 kV regulator to lift 33 kV voltage levels.	281k in yr1	Most realistic and cost effective.
		Non Network Option	Use generators, wait for proposed distributed generation and shift loads at capacity times.		
		Do Nothing	Restrict capacity and run assets up to maximum limits. Possible breach of regulatory voltage limits.		
WHAKAMARU	Cumulative Capacity	Network Option	Install second regulator at Maraetai substation site on the 33 kV line.	281k in yr5	This is the most cost effective solution providing voltage support throughout the year.
		Non Network Option	Provide voltage support with generators at times of know network constraint.		

TABLE 5-30: PLANNED WORK FOR 33 KV LINES CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
MARAETAI	Asset Renewal	Network Option	Replace breaker due to age, reliability and condition.	66k in yr14	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs. Risk of protection failure.		
MARAETAI	Cumulative Capacity	Network Option	Diversify off site with a modular substation near Ranganui Road.	450k in yr9	Cost, reliability improvements, fault current control and landowner issues. Will depend on Crusader Meats growth.
		Non Network Option	Install capacitors to support voltage.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MARAETAI	Cumulative Capacity	Network Option	Install modular substation on Sandel Road in Whakamaru.	450k in yr14	Most cost effective solution.
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
ATIAMURI	Asset Renewal	Network Option 1	Replace breaker due to age, reliability and condition.	84k in yr9	Parts for existing equipment are no longer available.
		Network Option 2	Maintain existing.		
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs. Risk of protection failure.		

WHAKAMARU & MOKAI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
MOKAI	Customer Connection	Network Option	Install a modular substation on Tirohanga road near the injection pumps, in conjunction with new 33 kV line and 11 kV upgrade. 100K for Switchgear and 400k for modular substation.	515K in yr2	Most cost effective solution. Satisfies customer requirements.
		Non Network Option	Install capacitors and generators, but this is not a cost effective solution.		
		Do Nothing	Miraka Milk Factory will not have the reliability the customer wants.		

TABLE 5-31: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
MANGAKINO	Reliability	Switches (Reliability Improvement)	463	Automate to TLC's current Network Standards.	23k in yr6
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T700 T701 T706	T700 3-Phase 300Kva. T701 Check loading and replace with a refurbished I tank of suitable size. Install RMU with 2 fuses and one for T2316. T706 Install refurbished 200kVA transformer.	45k in yr3 45k in yr2 45k in yr1
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1081	Check loading; rebuild structure with 100 kVA if loading light enough, otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	56k in yr5
MOKAI	Reliability	Switches (Reliability Improvement)	474 493 446	474 Check sites. 446 Check sites. 493- Automate Switch, new pole and ENTEC switch.	45k in yr13 34k in yr1 45k in yr13
	Cumulative Capacity	Development Feeder	FED123	Upgrade conductor to Mink on Tirohanga Road, two stages.	309K in yr2 721k in yr6
PUREORA	Reliability	Switches (Reliability Improvement)	423	Automate to TLC's current Network Standards.	23k in yr3
TIHOI	Reliability	Switches (Reliability Improvement)	454	Automate to TLC's current Network Standards.	34k in yr2
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1618	Construct to TLC's current Network Standards.	7k in yr8
TIROHANGA	Reliability	Switches (Reliability Improvement)	434	Automate to TLC's current Network Standards.	23k in yr2
	Cumulative Capacity	Development Feeder	FED129	More Feeder ties and a new modular substation at Mine road. Will depend on forest conversion to dairying.	506k in yr12
WHAKAMARU	Hazardous Asset Renewals	Hazardous Underground Refurbishment	FED120	RMU and 300 kVA TX for T2523 and remove T2524 and T2521. Through-joint at T2523 to T2525. Replace LV cable around village with 4c Cable, new 16mm^2 N/S street light cable and TUDs pillar boxes. May need to include replacement of service main to boxes on side of houses.	515k in yr4

TABLE 5-32: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

5.6.1.4 Assets connected to Ongarue Point of Supply

Figure 5-15 indicates the area supplied from the Ongarue Point of supply and the connected feeders geographical location. Figure 5-16 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 33 to Table 36 list the development work planned for assets connected to the Ongarue point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

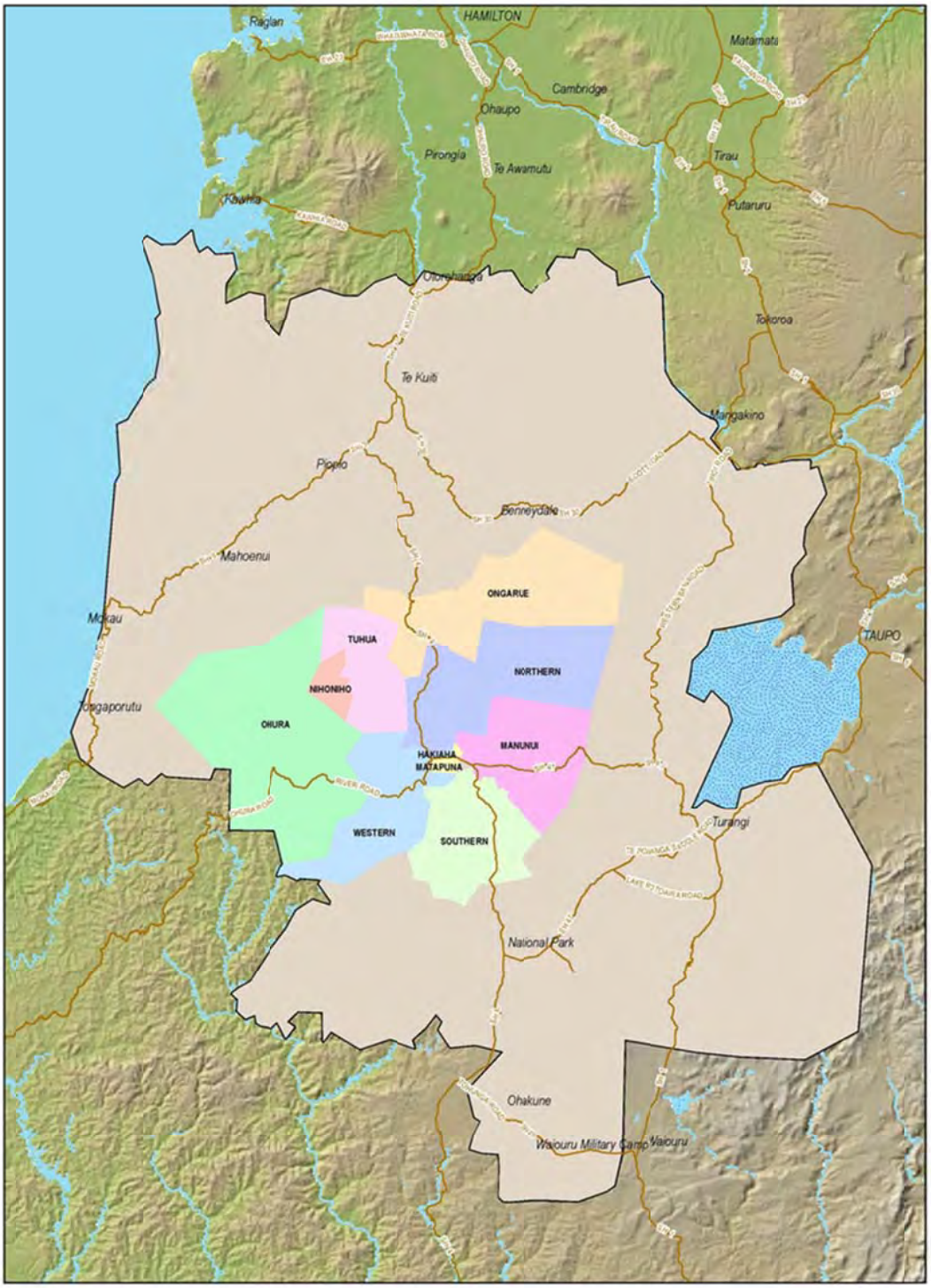


FIGURE 5-15: ONGARUE SUPPLY AREA AND FEEDER LOCATIONS

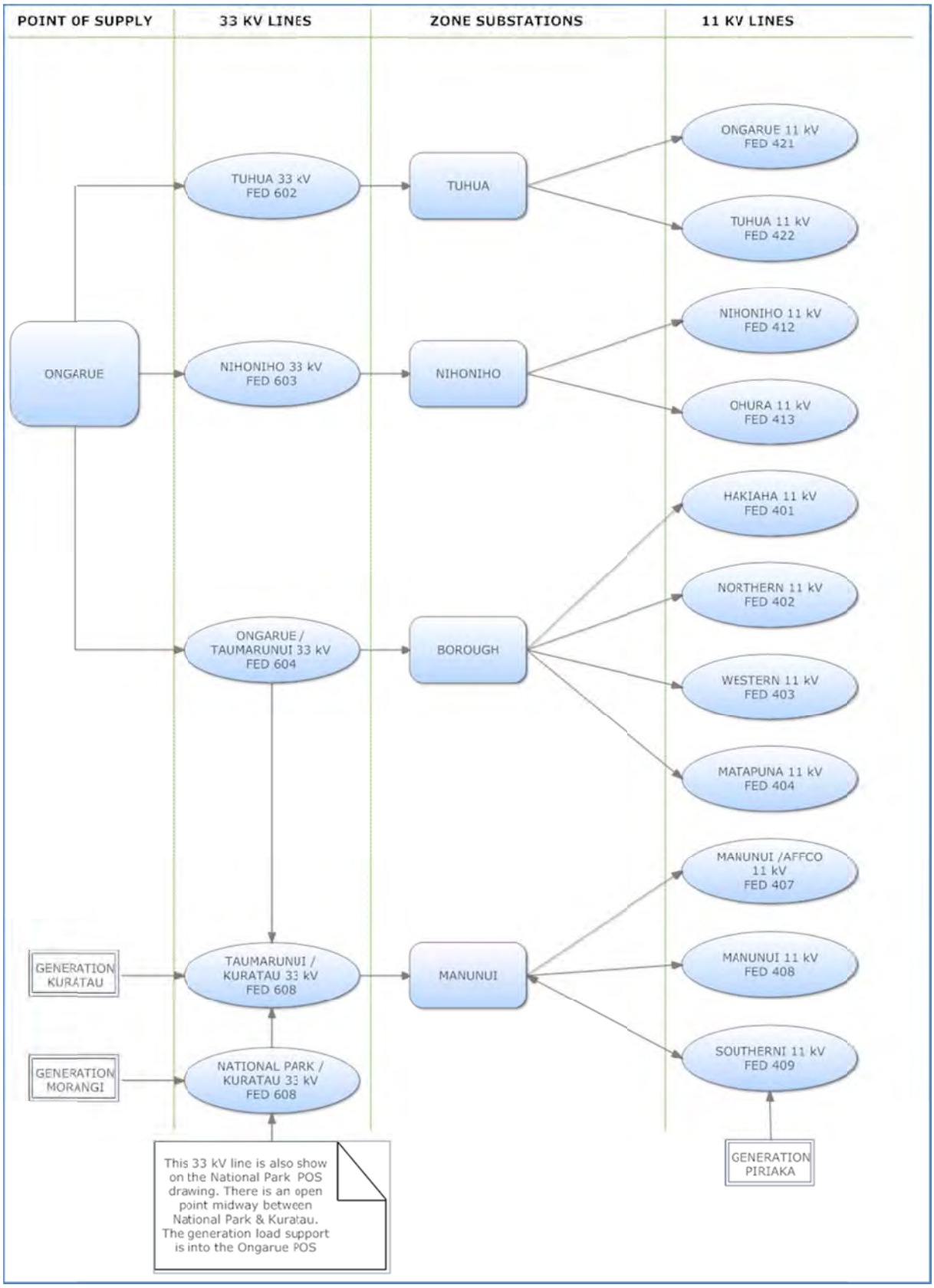


FIGURE 5-16: CONNECTION DIAGRAM OF ASSETS CONNECTED TO ONGARUE POS

ONGARUE POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
ONGARUE	Asset Renewal	Network Option	Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho lines. Remove old Nihoniho breaker. Needs 4 line reclosers and one or two automated 33kV switches. Allows splitting of feeders and isolation of Transpower supply. Some 33kV cabling will be necessary. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	675k in yr2	It is more cost effective for TLC to have its own 33kV bus system, than pay the high annual connection charges associated with circuit breakers to Transpower. Typically, Transpower's annual charges are 1.5 times the capital cost of a circuit breaker. There is a potential to remove 3 Transpower owned circuit breakers and reduce site hazards and improve operational ease. Reliability and security will also benefit.
		Non Network Option	By-pass the site.		
		Do Nothing	Increases in customer charges.		

TABLE 5-33: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO ONGARUE POS

ONGARUE POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
ONGARUE / TAUMARUNUI	Cumulative Capacity	Network Option 1	Regulators installed on Kuratau supply at Manunui To be done with Manunui rebuild.	281k in yr2	Lowest cost given low growth of area, the assets that are in place and the income available from the area.
		Network Option 2	Negotiate contract with Transpower to take supply from Taumarunui railway supply. This is a more expensive option.		
		Non Network Option	Install large generators. More expensive option.		
		Do Nothing	Restrict capacity to customers.		
ONGARUE / TAUMARUNUI	Cumulative Capacity	Network Option	Install reactive power capacitors.	103k in yr4 103k in yr15	This is the most cost effective solution.
		Non Network Option	Support voltage with generators.		
		Do Nothing	Customers will not have the reliability that they require.		

TABLE 5-34: PLANNED WORK FOR 33 KV LINES CONNECTED TO ONGARUE POS

ONGARUE POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TUHUA	Hazardous Asset Renewals	Network Option 1	Replace with modular substation.	382k in yr13	The present site has had some barriers put up but it does not achieve an acceptable long-term solution. Solves hazard control, equipment age, environmental and other site. Given the safety constraint, the modular substation is the best option.
		Network Option 2	Modify existing site by installing bunding, oil separation and earthquake restraints. Discounted due to age of equipment on site.		
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages. Hazards due to access and incorrect equipment operation (protection).		
NIHONIHO	Hazardous Asset Renewals	Network Option	Replace with modular substation.		
		Network Option	Replace fence and upgrade transformer.	225k in yr13	Landowner issues associated with present site and need to move site if mine reopens. (DOC is landowner)
		Non Network Option	None available.		
		Do Nothing	Leave as is, possible security breaches due to deteriorating fence condition.		

ONGARUE POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
BOROUGH	Environmental (River flooding)	Network Option 1	Diversify with modular substations. Located above slip on main road.	377k in yr10	Diversity increases reliability.
		Network Option 2	Construct further 11kV links to Manunui Substation. More costly than option 1.		
		Non Network Option	Install generators in a separate location to support back feed supplies from Manunui substation.		
		Do Nothing	Leave site as is and risk the site flooding.		
BOROUGH	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr5	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
MANUNUI	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformer.	90k in yr2	Cost
		Non Network Option	None available.		
		Do Nothing	Transformer could fail is left.		
MANUNUI	Hazardous Asset Renewals	Network Option 1	Rebuild site.	169k in yr2	Most cost effective option.
		Network Option 2	Modify site for bunding and earthquake restraints		
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
MANUNUI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	28k in yr2	Manual bund draining has to be done after rain. Costly and not robust.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		

TABLE 5-35: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO ONGARUE POS

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
HAKIAHA	Reliability	Switches (Reliability Improvement)	5.19 5.3 5831 5.4 5.23	Automate to TLC's current Network Standards.	45k in yr10 38k in yr15 34k in yr3 38k in yr15 38k in yr15
		Back feed Reliability Improvements	FED401	Low voltage ties between transformers in CBD. Do in conjunction with switch gear for 01A38 and 01A82. Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	113k in yr2 131k in yr12
	Hazardous Asset Renewals	Switches (Hazard)	FED401	Add 11 kV switch gear for 01A38 and 01A82.	56k in yr2
		Low and Hazardous Two Pole Structures	01A31 01B11	01A31 Construct to TLC's current Network Standards. 01B11- Rebuild structure with safer LV wiring, Raise the height of the transformer.	45k in yr7 45k in yr4
MANUNUI	Reliability	Switches (Reliability Improvement)	5912 5914	Automate to TLC's current Network Standards.	34k in yr4 34k in yr2
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	07K11	07K11- Replace two pole structure with standard single pole SWER isolating structure.	49k in yr3
			08J04	08J04- Replace with standard single pole structure.	49k in yr9
			08J07	08J07 Construct to TLC's current Network Standards.	45k in yr7
			08J10	08J10 Maintenance.	7k in yr8
			08K14	08K14 Replace pole mounted transformer with refurbished ground mounted transformers.	49k in yr3
			08L17	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level.	45k in yr5

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
MATAPUNA	Reliability	Switches (Reliability Improvement)	1.7 1.5 5357 5838 1.6	Automate to TLC's current Network Standards.	26k in yr7 26k in yr7 45k in yr6 45k in yr4 26k in yr7
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	01A75	Construct to TLC's current Network Standards.	44k in yr8
		Ground Mount Transformers: Condition & Hazards	01A36 01A70 01B20 01B02 01B24 01B25	Check sites and improve site hazards and transformer condition as required.	56k in yr12 45 in yr7 34k in yr14 34k in yr14 45k in yr6 34k in yr14
NORTHERN	Reliability	Switches (Reliability Improvement)	5119 6127 5164	Automate to TLC's current Network Standards.	45k in yr12 28k in yr3 45k in yr12
	Hazardous Asset Renewals	Switches (Hazard)	01A52 07I14 08I19	Install Switchgear.	45k in yr9 45k in yr12 45k in yr13
		Low and Hazardous Two Pole Structures	01A46	01A46- Replace structure and install a refurbished ground mounted transformer.	45k in yr4
			01A50	01A50- Rebuild structure 11 kV only 4m above ground. Ground mount transformer, if possible use a second hand 100 kVA.	48k in yr1
			06H11	06H11- Raise equipment on structure, recloser at only 3.75m above the ground.	48k in yr1
			08I02	08I02- Replace with a ground mounted refurbished transformer. Check loadings.	51k in yr8
			T4055	T4055- Raise equipment on structure to over regulation height and maintain clearances.	45k in yr8
		Ground Mount Transformers: Condition & Hazards	01A48 07I12 T4025	Check sites and improve site hazards and transformer condition as required.	56k in yr14 45k in yr12 45k in yr11

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
NIHONIHO	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	06E01	Construct to TLC's current Network Standards.	39k in yr8
OHURA	Reliability	Switches (Reliability Improvement)	5758	Automate to TLC's current Network Standards.	45k in yr11
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	10E09	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	39k in yr11
			07D03	07D03 Construct to TLC's current Network Standards.	45k in yr9
			07D08	07D08 Construct to TLC's current Network Standards.	45k in yr6
			07D11	07D11 Rebuild structure with standard single pole isolating SWER transformer structure.	39k in yr13
			07D16	07D16 Replace with standard single pole isolating SWER structure.	39k in yr11
			09C05	09C05 Construct to TLC's current Network Standards.	45k in yr12
			T4130	T4130 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	39k in yr13
		Ground Mount Transformers: Condition & Hazards	07D24	Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	45k in yr5
ONGARUE	Reliability	Switches (Reliability Improvement)	5462	Automate to TLC's current Network Standards.	45k in yr14
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	01K02	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA TX.	45k in yr3
			02K08	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	56k in yr5
			02K16	02K16 Rebuild structure 11 kV bushing area below regulation height.	56k in yr6
			04I01	04I01 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Check loading on 04I01 as load flow program indicates TX could be overloaded.	30k in yr1
			T4128	T4128 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Look at new options as 04I01 may be overloaded.	30k in yr1

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
SOUTHERN	Reliability	Switches (Reliability Improvement)	5136	Automate to TLC's current Network Standards.	45k in yr6
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	09K02	09K02 Construct to TLC's current Network Standards.	39k in yr9
			09K25	09K25 Rebuild structure with standard single pole Isolating SWER structure.	42k in yr5
			09K50	09K50 Check loading on transformer. Either 100 kVA standard single pole or 200 kVA refurbished ground Mount.	42k in yr4
			10K14	10K14 Construct to TLC's current Network Standards.	39k in yr8
			11K11	11K11 Construct to TLC's current Network Standards.	45k in yr7
			12K08	12K08 Construct to TLC's current Network Standards.	39k in yr11
TUHUA	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	05G03	Lift equipment over regulation height and maintain clearances.	23k in yr3
WESTERN	Reliability	Switches (Reliability Improvement)	5795 5404	Automate to TLC's current Network Standards.	28k in yr2 28k in yr2
	Hazardous Asset Renewals	Switches (Hazard)	08I31 08I55	Install RMU's.	45k in yr13 45k in yr3
		Low and Hazardous Two Pole Structures	08H03	08H03 Construct to TLC's current Network Standards.	45k in yr6
			08I21	08I21 Raise equipment on structure to above regulation height for 11 kV from ground level. Maintain clearances.	56k in yr5
		Ground Mount Transformers: Condition & Hazards	08I08 T4012	Check sites and improve site hazards and transformer condition as required.	34k in yr14 45k in yr15

TABLE 5-36: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO ONGARUE POS

5.6.1.5 Assets connected to Tokaanu Point of Supply

Figure 5-17 indicates the area supplied from the Tokaanu Point of supply and the connected feeders geographical location. Figure 5-18 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 37 to Table 40 lists the development work planned for assets connected to the Tokaanu point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

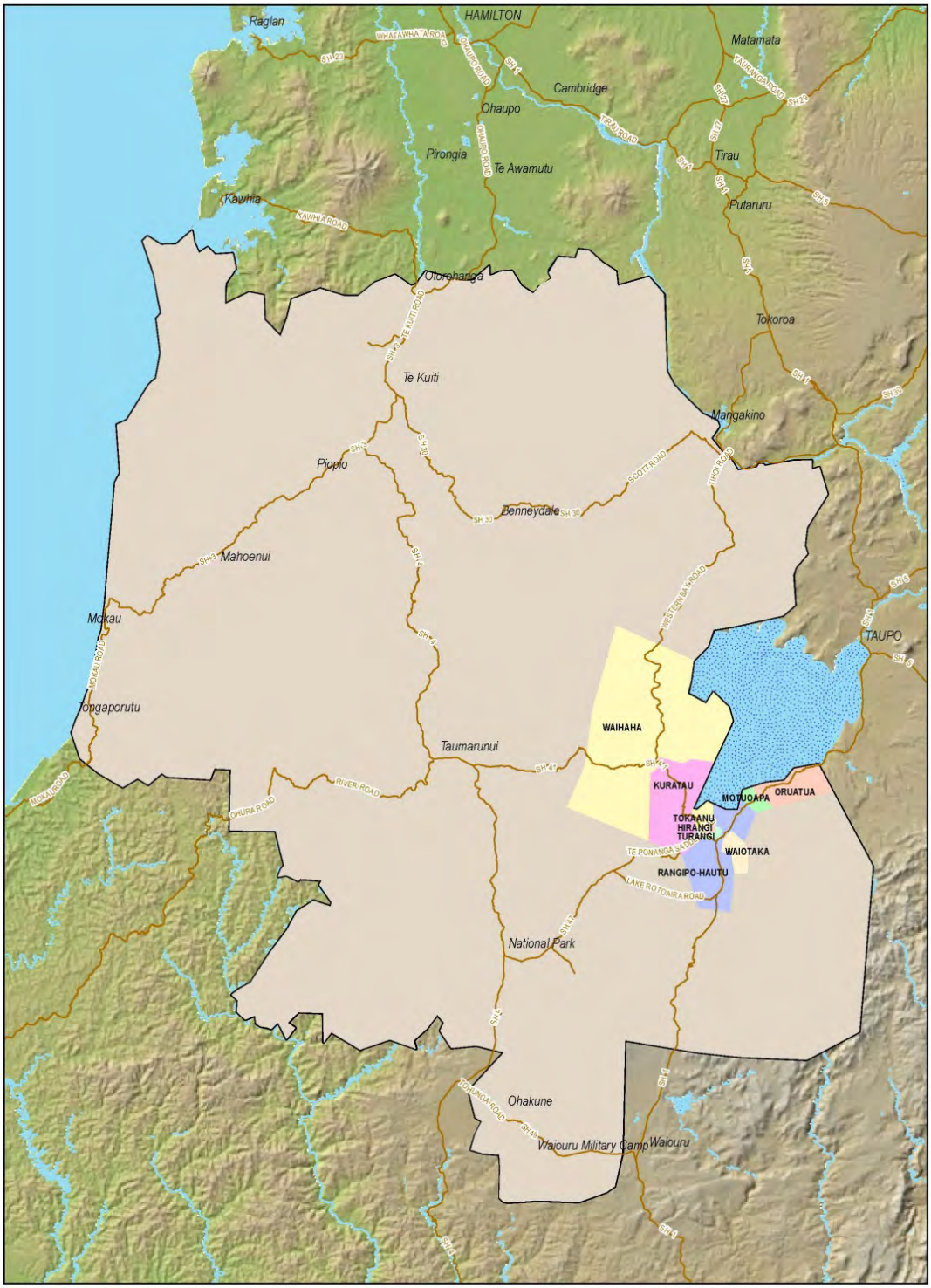


FIGURE 5-17: TOKAANU SUPPLY AREA AND FEEDER LOCATIONS

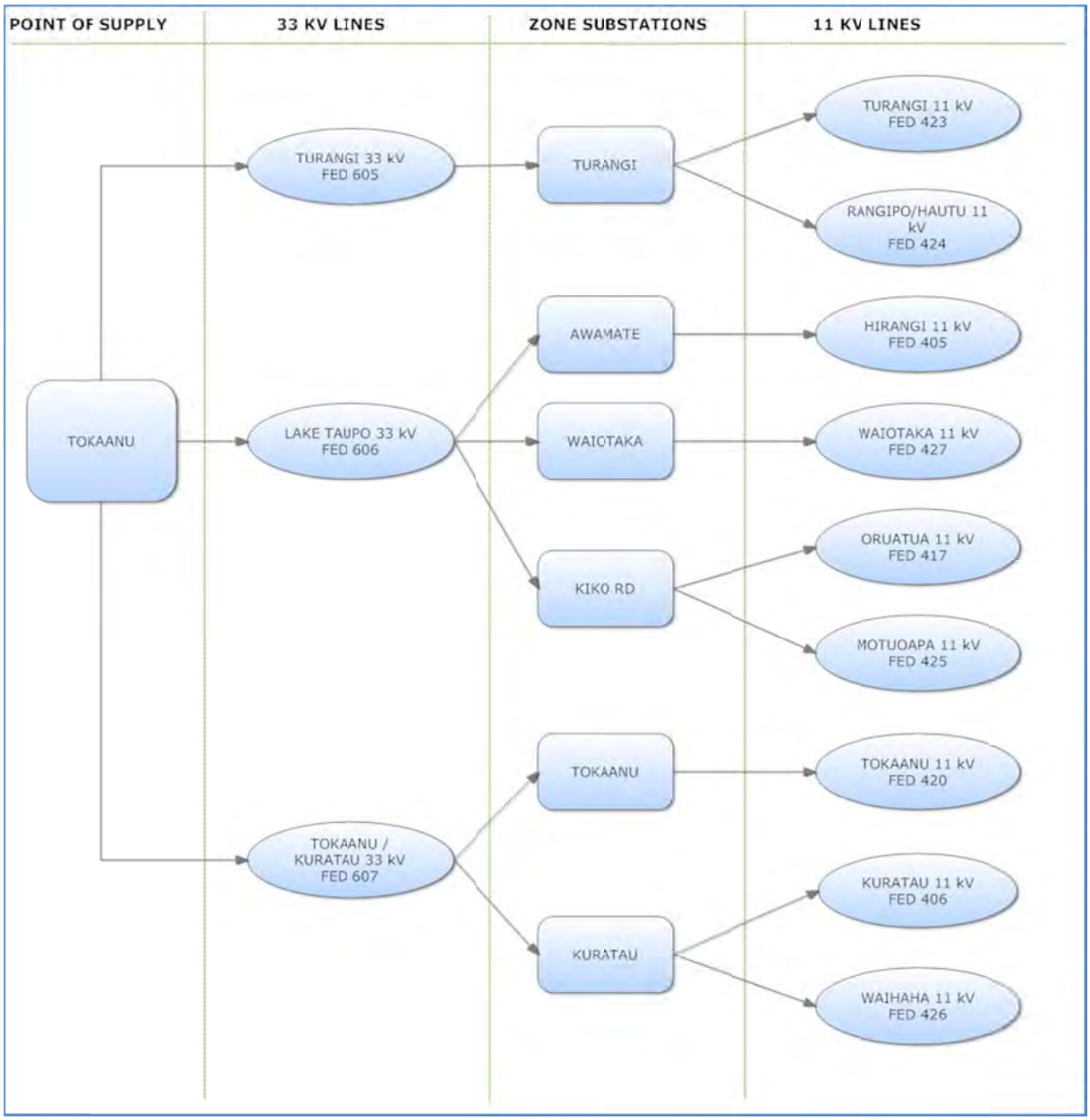


FIGURE 5-18: CONNECTION DIAGRAM OF ASSETS CONNECTED TO TOKAANU POS

TOKAANU POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TOKAANU	Hazardous Asset Renewals	Network Option	Install switchgear capable of breaking a capacitive circuit. Sectos switch in stock can be used for this project.	68k in yr1	When Tokaanu GXP is out of service, the capacitors in the ripple plant need to be isolated from the 33 kV line from Kuratau.
		Non Network Option	None Available		
		Do Nothing	Hazard risk to staff		

TABLE 5-37: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO TOKAANU POS

TOKAANU POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
LAKE TAUPO 33	Hazardous Asset Renewals	Network Option 1	Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues.	338k in yr12	Crossing of Tongariro River where fishing is extensive. Maori landowner issues. Lower cost than cable.
		Network Option 2	Rebuild with cable.		
		Non Network Option	Use generators to back up supply.		
		Do Nothing	More prone to faults and customer increase in customer minutes. SMS hazards associated with river crossing.		
TOKAANU / KURATAU 33 kV	Reliability	Network Option	Switches (Reliability Improvement)	36k in yr3	5984 - Automate to TLC's current Network Standards.

TABLE 5-38: PLANNED WORK FOR 33 KV LINES CONNECTED TO THE TOKAANU POS

TOKAANU POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TURANGI	Hazardous Asset Renewals	Network Option	Add additional 33 kV switchgear. New 33 kV in year 12/13. Underground and remove double cct to be done at same time as far as 5673 tap-off. (See 11kV line renewals.) 11 kV breakers in year 15/16 to split heavily loaded feeder.	206k in yr1 155k in yr4	Present arrangement is complex, non-standard and consists of old components not designed for the job they are doing. Hazards and reliability / security is improved.
		Non Network Option	None available.		
		Do Nothing	Confusing set up for staff to work on.		
TURANGI	Hazardous Asset Renewals	Network Option 1	Rebuild site.		
		Network Option 2	Rebuild fence.	68k in yr1	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible security breaches if fence left to deteriorate.		
KURATAU	Cumulative Capacity	Network Option 1	Put in a modular substation at end of network close to an existing 33kV line.	450k in yr10	Most cost effective way of increasing capacity and achieving improvements.
		Network Option 2	Put in a second transformer at present site.		
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		

TABLE 5-39: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO TOKAANU POS

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
KURATAU	Reliability	Switches (Reliability Improvement)	5921 6557 6355 6353	Automate to TLC's current Network Standards.	34k in yr6 34k in yr7 34k in yr5 34k in yr4
	Cumulative Capacity	Feeder Development	FED406	Line rebuilds: SWER replacement associated with Kuratau development. Line rebuilds i.e. SWER to 3 phase rebuilds associated with Kuratau development.	56k in yr11 56k in yr9
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	08R22	3-Phase 100kVA.	3k in yr7
		Switches (Hazard)	08R08 08R20 09R14 09R16 10S41	08R08 Install Switchgear. 08R20 Install transformer with RTE switch. 09R14 Install a Xiria in association with Transformer 09R14 & work on 09R16. 09R16 Install RTE switch. 10S41 Install Switchgear.	45k in yr10 45k in yr3 45k in yr4 45k in yr4 45k in yr7
		Low and Hazardous Two Pole Structures	08R09 09R27 09R28	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available. 09R27 Lift equipment on pole to above regulation height and maintain clearances. 09R28 Construct to TLC's current Network Standards.	39k in yr3 39k in yr4 45k in yr10
MOTUOAPA	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	09T04	Replace with ground mounted 300 kVA; use a refurbished transformer.	56k in yr3
	Reliability	Ground Mount Transformers: Condition & Hazards	T4104	3-Phase 300kVA.	3k in yr7

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
ORUATUA	Hazardous Asset Renewals	Hazardous River Crossing	FED417	Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	158k in yr3
		Switches (Hazard)	09U11	Install switch gear near or associated with 09U11.	56k in yr3
		Low and Hazardous Two Pole Structures	09U07	09U07 Replace with a ground mounted transformer. Pole requires replacing and LV through trees. Earth mat looks to be damaged.	68k in yr1
			09U10	09U10 Replace with ground mounted transformer. Adjacent high wooden fence makes any structure a hazard.	68k in yr1
			09U12	09U12 Construct to TLC's current Network Standards.	56k in yr9
RANGIPO/HAUTU	Reliability	Switches (Reliability Improvement)	5207	Automate to TLC's current Network Standards.	45k in yr3
			5963		39k in yr11
		Developed Feeder	FED424	Add LV links through the town.	113k in yr15
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10S47	10S47 3-Phase 300kVA.	34k in yr13
			11S16	11S16 3-Phase 300kVA.	3k in yr7
			11S18	11S18 3-Phase 300kVA.	45k in yr11
		Switches (Hazard)	10S03	10S03 Install switchgear.	45k in yr5
			10S13	10S13 Install switchgear.	45k in yr11
			10S49	10S49 11 kV Cable hard on to 11 kV line, replace pole fit DDO's or Vertical ABS and fuses.	23k in yr13
			FED424	FED424 Hazard from Genesis 33 kV Line crossing.	56k in yr9
		Low and Hazardous Two Pole Structures	11S04	Check loading on transformer, downsize TX as required. Rebuild with standard single pole structure.	28k in yr2
TOKAANU	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10R20	3-Phase 200kVA.	45k in yr15

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
TURANGI	Reliability	Switches (Reliability Improvement)	6191	6191 Automate 6191 tie to Hirangi Feeder from Turangi. This is an existing Magnefix therefore the switch will need to be changed.	56k in yr1
			6186	6186 Automate to TLC's current Network Standards.	11k in yr8
			5208	5208 Install a 4 way Xiria at tap-off 5208 to supply Turangi and have a parallel with Rangipo Hautu.	56k in yr1
			5209	5209 Automate to TLC's current Network Standards.	68k in yr8
		Feeder Development	FED423	Add LV links through the town. Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40.	113k in yr13 281k in yr8
TURANGI	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10S24	10S24 3-Phase 100kVA.	3k in yr7
			10S26	10S26 Tin shed with Magnefix. Tape up leads. Open LV rack.	45k in yr4
			10S29	10S29 Open LV rack in tin shed.	41k in yr5
			10S30	10S30 Open LV rack in tin shed.	41k in yr13
			10S31	10S31 Tin shed with Magnefix. Tape up leads. Open LV rack.	45k in yr1
			10S39	10S39 3-Phase 200kVA.	45k in yr6
			10S41	10S41 Install RTE switch. Do in conjunction with 10S42.	45k in yr2
			10S42	10S42 Install front access TX with 11kV internal fusing. Do in conjunction with 10S41.	45k in yr2
			10S44	10S44 Open LV rack in tin shed. Replace with GMT.	41k in yr3
			10S46	10S46 Tin shed with Magnefix. Tape up leads. Open LV rack.	45k in yr1
		Switches (Hazard)	10S38	Install Switch Gear	45k in yr10
WAIHAHA	Reliability	Switches (Reliability Improvement)	5150	Automate to TLC's current Network Standards.	45k in yr2
	Cumulative Capacity	Feeder Development	FED426	Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	225k in yr8 169k in yr11
	Hazardous Asset Renewals	Switches (Hazard)	07R13	Install RMU.	45k in yr6
		Low and Hazardous Two Pole Structures	04Q06	04Q06 Construct to TLC's current Network Standards.	39k in yr9
			07Q14	07Q14 Rebuild structure next to State Highway. Existing equipment is below regulation height.	56k in yr2

TABLE 5-40: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO TOKAANU POS

5.6.1.6 Assets connected to National Park Point of Supply

Figure 5-19 indicates the area supplied from the National Park POS and the connected feeders geographical location. Figure 5-20 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 5-41 to Table 5-44 lists the development work planned for assets connected to the National Park point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

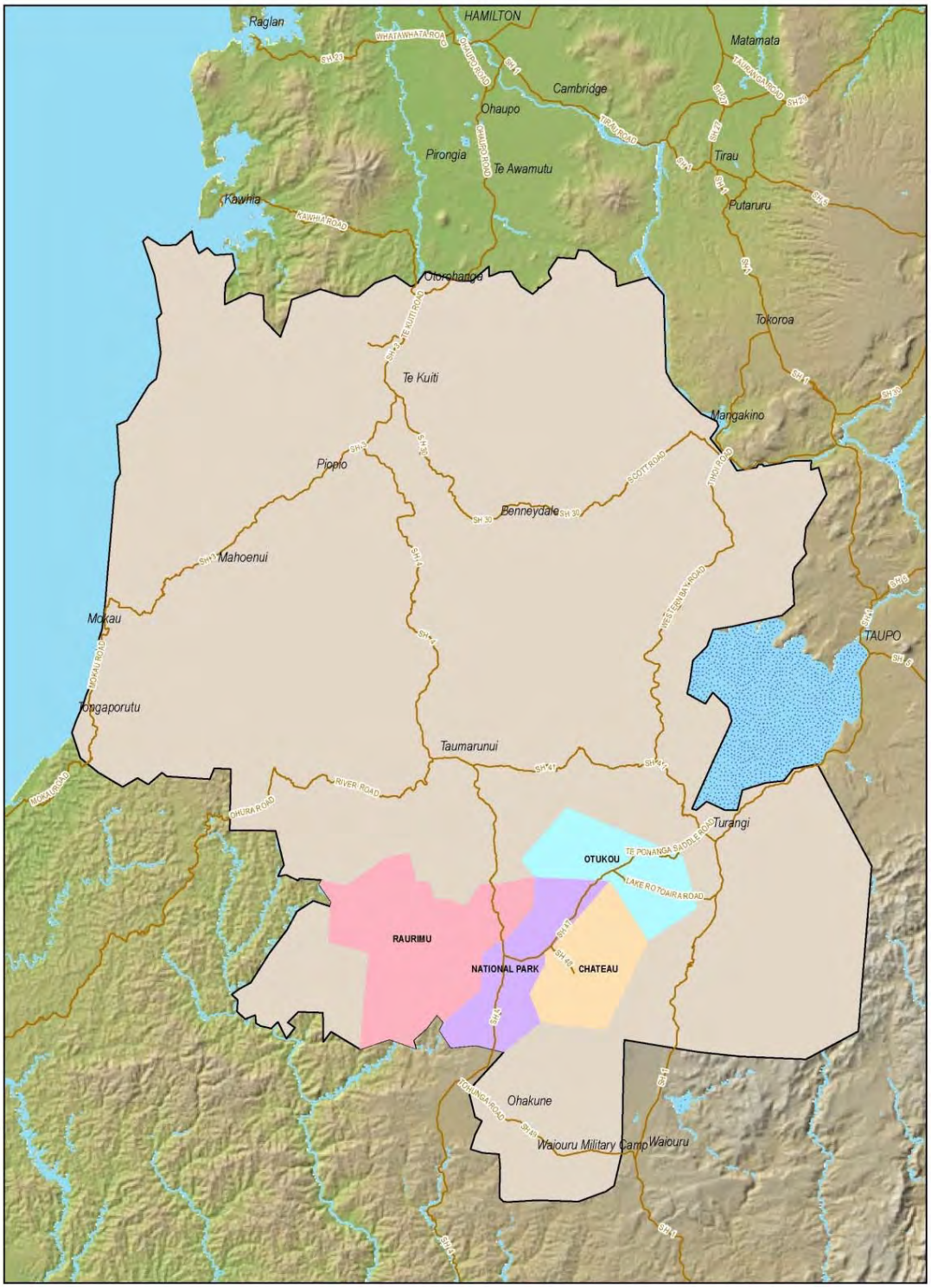


FIGURE 5-19: NATIONAL PARK SUPPLY AREA AND FEEDER LOCATIONS

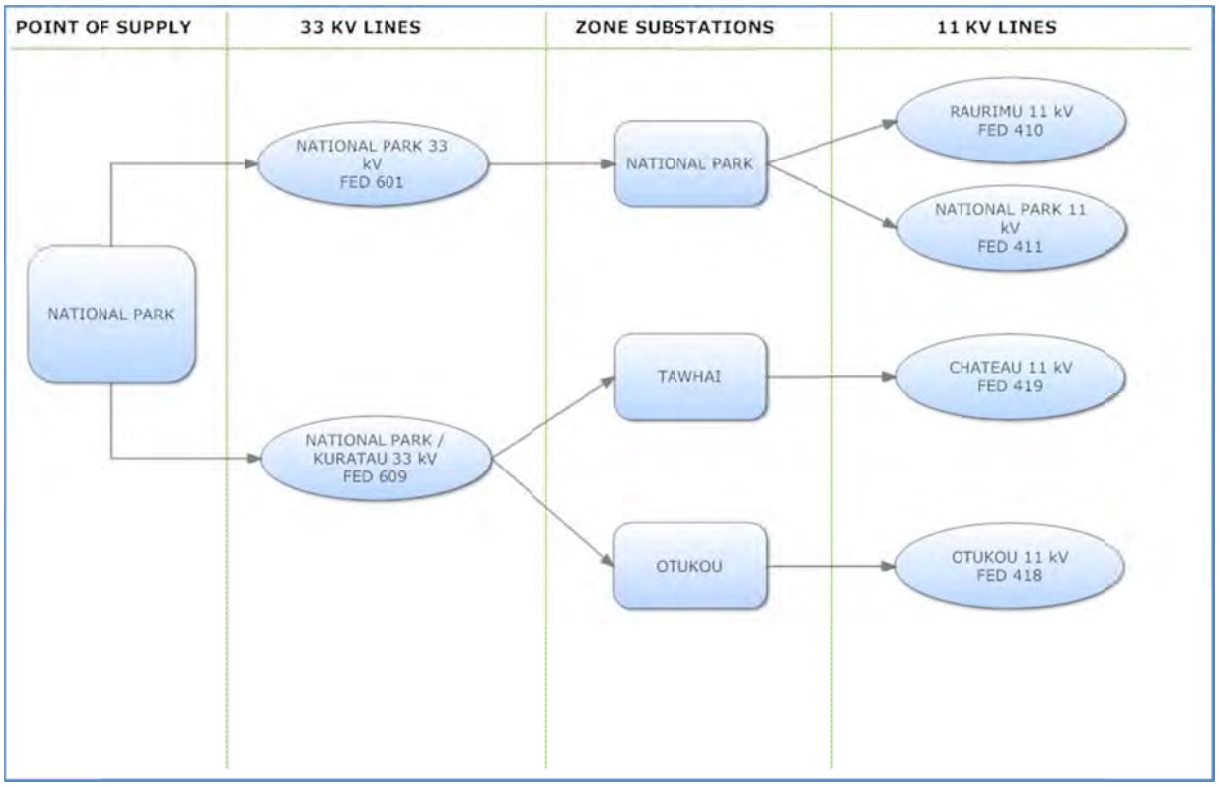


FIGURE 5-20: CONNECTION DIAGRAM OF ASSETS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
NATIONAL PARK	Hazard Asset Renewals	Network Option	ZSub 516Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers and containerise the switch gear for the 11 kV Feeders. This work aligns with the installation of a new modular substation with the switch gear in a container (see Zone Substations).	675k in yr2	The principal driver of this project is to remove the hazards associated with the existing load control plant and outgoing 11 kV protection. A by product will be lower Transpower connection charges achieved through rationalising the number of outgoing 33 kV circuits. The most cost effective solution is to rebuild the site using a modular approach.
		Non Network Option	Bypass site.		
		Do Nothing	Increases in customer charges.		

TABLE 5-41: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Asset**	**Description**	**Year & Cost Estimate**	**Principle Reason for this Option Choice**
NATIONAL PARK / KURATAU 33 KV	Hazardous Asset Renewals	Network Option	Low and Hazardous Two Pole Structures.	62k in yr8	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transformer structure to make safer. Investigate a refurbished 33 kV / 400 v transformer. A lot of children visit this area; structure needs to be hazard controlled.

TABLE 5-42: PLANNED WORK OF 33 KV LINES

NATIONAL PARK POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year & Cost Estimate**	**Principal Reason for this Option Choice**
NATIONAL PARK	Environmental	Network Option 1	ZSub 501. Rebuild Site. Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	318k in yr2	Cost and landowner consideration given equipment is sited on Transpower land. This solution gives the best overall solution. The site is next to a major State highway, and in a high tourist area with DOC land adjacent to the TP site; therefore a tidy, environmentally sound and secure solution is required.
		Network Option 2	Rebuild fence and include bunding, oil separation and earthquake restraints. This will not be practical given the site restrictions.		
		Non Network Option	None available.		
		Do Nothing	Leave as existing. Fence is deteriorating and possible environmental contamination due to oil leakages during an earthquake.		
OTUKOU	Environmental	Network Option 1	Replace with modular substation		
		Network Option 2	ZSub512. Modify existing site by installing bunding, oil separation and earthquake restraints.	68k in yr12	Cost of restraints, bunding and separation is less than a modular substation.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		

NATIONAL PARK POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year & Cost Estimate**	**Principal Reason for this Option Choice**
TAWHAI	Hazardous Asset Renewals	Network Option 1	Rebuild site.		
		Network Option 2	ZSub513. Renew fence.	56k in yr3	Adequate fencing is important.
		Non Network Option	None available.		
		Do Nothing	Leave as is, possible security breaches due to deteriorating fence condition.		
TAWHAI	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	ZSub513. Refurbish transformer.	90k in yr1	Oil test results are showing that provided it is serviced, transformer will likely give further reliable service.
		Non Network Option	None available.		
		Do Nothing	Transformer could fail if not refurbished.		
TAWHAI	Cumulative Capacity	Network Option	ZSub513. Install a second transformer. Use a transformer out of Turangi.	675k in yr8	It is likely that customers on mountain will want both options pursued. RAL generation will also increase the reliability of supply to the ski fields. A second cable to mountain will also have to be installed when capacity of existing transformer is reached.
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Ski field at Whakapapa will not be able to expand.		

TABLE 5-43: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
CHATEAU	Cumulative Capacity	Feeder Development	FED419	Cable from Tavern to Water Tower, 2nd Cable. Add second cable from Tawhai to Tavern.	338k in yr10 563k in yr13
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	16N04 16N05 16N06 16N07	16N04 1-Phase 15kVA. 16N05 3-Phase 50kVA. 16N06 3-Phase 200kVA. 16N07 3-Phase 200kVA.	28k in yr12 45k in yr7 51k in yr13 51k in yr13
		Switches (Hazard)	08I03 08I34 15N02 15N09 15N11 15N12 16N01 16N02 16N09 16N17 16N21 16N28 16N29 T4066	08I03 Add 11 kV switchgear to transformer. 08I34 Add 11 kV switchgear to transformer. 15N02 Add 11 kV switchgear to transformer. 15N09 Add 11 kV switchgear to transformer. 15N11 Add 11 kV switchgear to transformer. 15N12 Add 11 kV switchgear to transformer. 16N01 Add 11 kV switchgear to transformer. 16N02 Add 11 kV switchgear to transformer. 16N28 Add 11 kV switchgear to transformer. 16N29 Add 11 kV switchgear to transformer. 16N09 Install switchgear. 16N17 Add switchgear to this site. 16N21 Add 11 kV switchgear to transformer. T4066 Upgrade transformer, install Xiria.	45k in yr10 45k in yr11 45k in yr12 45k in yr13 45k in yr9 45k in yr15 45k in yr6 45k in yr7 45k in yr5 45k in yr2 45k in yr3 45k in yr8 45k in yr8 45k in yr1
NATIONAL PARK	Reliability	Switches (Reliability Improvement)	5151 5146	Automate to TLC's current Network Standards.	45k in yr4 45k in yr9
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	14L05 14L12	14L05 3-Phase 500kVA. 14L12 Install transformer with RTE switch.	45k in yr15 45k in yr3
		Switches (Hazard)	15L07	Install Switch Gear.	45k in yr6
		Low and Hazardous Two Pole Structures	15K06 15L05 16L02	15K06 Construct to TLC's current Network Standards. 15L05 Transformer is close to motel balcony. Ground mount transformer, check loadings for transformer size. 16L02 Construct to TLC's current Network Standards.	56k in yr12 45k in yr2 45k in yr7

NATIONAL PARK POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
OTUKOU	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	12O01	Renew Structure. (This transformer needs to be checked for loading.)	39k in yr9
	Reliability	Ground Mount Transformers: Condition & Hazards	12N08	Renew with modern equivalent.	45k in yr12
RAURIMU	Reliability	Switches (Reliability Improvement)	FED410	Install Recloser for Retaruke tap-off at Raurimu Hill.	56k in yr1
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	13I10 T4077 T4132	13I10 Renew Structure. Check the loading on this transformer ETAP load flows indicate that it may be overloaded. Rebuild site. Costs slipped over 13I10 and T4132 as there are two SWER isolating transformers on the one structure. T4077 Construct to TLC's current Network Standards. T4132 Renew Structure. Check the loading on this transformer ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k in yr3 45k in yr10 30k in yr3

TABLE 5-44: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO NATIONAL PARK POS

5.6.1.7 Assets connected to Ohakune Point of Supply

Figure 5-21 indicates the area supplied from the Ohakune POS and the connected feeders geographical location. Figure 5-22 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 5-45 to Table 5-46 lists the development work planned for assets connected to the Ohakune point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

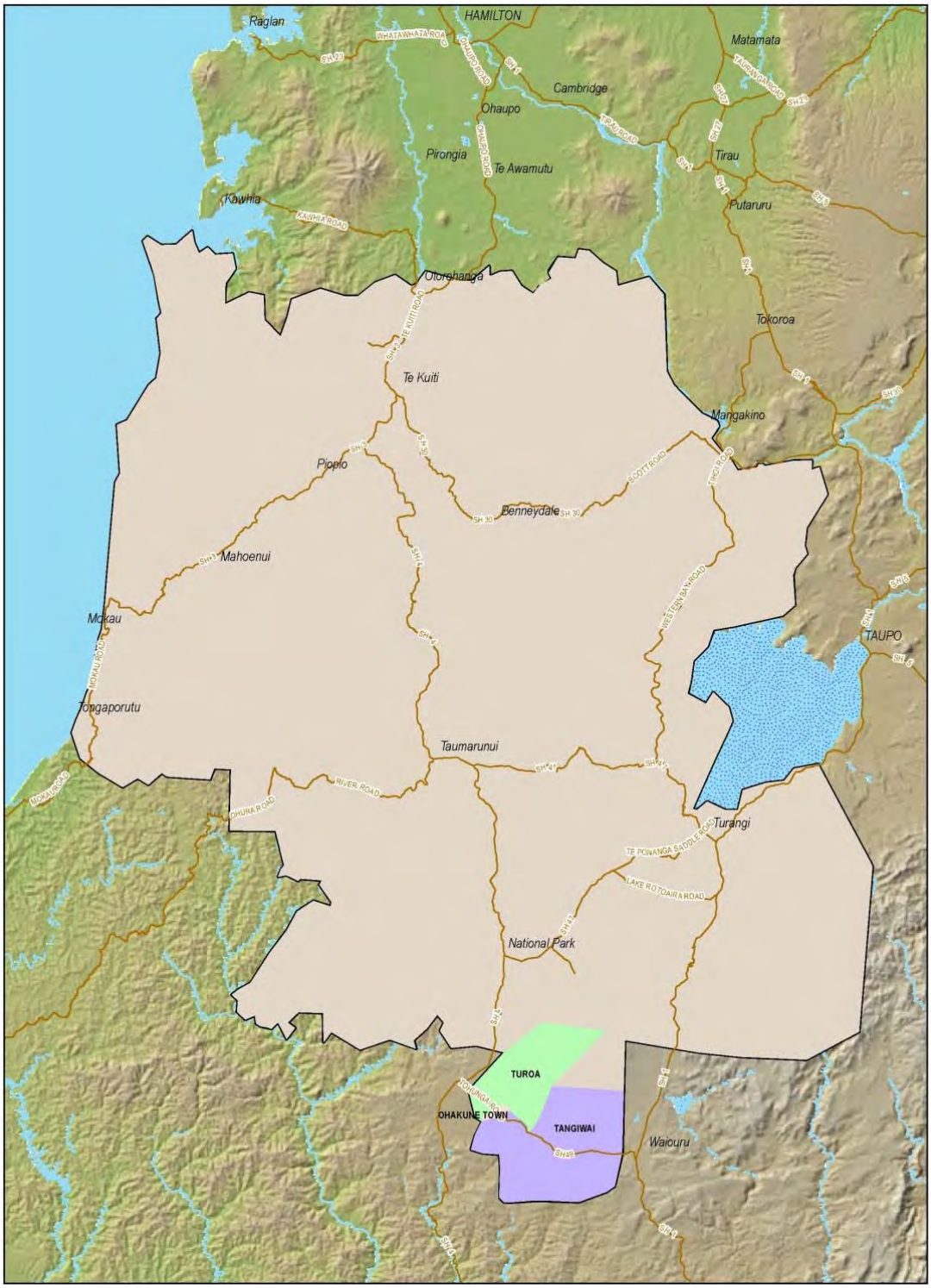


FIGURE 5-21: OHAKUNE SUPPLY AREA AND FEEDER LOCATIONS

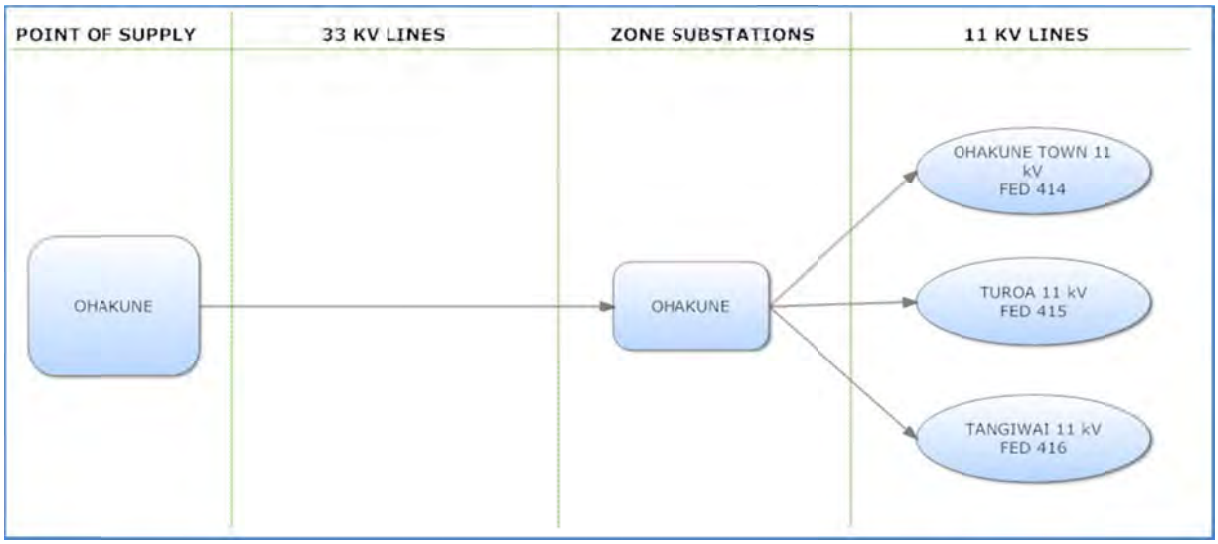


FIGURE 5-22: CONNECTION DIAGRAM OF ASSETS CONNECTED TO OHAKUNE POS

OHAKUNE POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
OHAKUNE	Cumulative Capacity	Network Option 1	Upgrade Ohakune.		
		Network Option 2	ZSub517. Take supply for part of area from neighbouring Tangiwai Transpower substation.	464k in yr1	Lowest cost option to buy time for transformer upgrade of neighbouring Ohakune GXP. Will provide another 1 MVA of capacity during the ski season and backup for Ohakune. Work involves the installation of regulators, fault reducing transformer and 11 kV load control plant.
		Non Network Option	Generators to support voltage at peak loadings.		
		Do Nothing	TLC has several times in the pass taken capacity loads from Transpowers Ohakune site and have been threatened with disconnection form their supply. Customers load applications are currently being turned down until more capacity is available.		
OHAKUNE	Cumulative Capacity	Network Option 1	ZSub517. The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. Break into the circuit before the cross bus. Split one feeder off. Have capacity for a spare feeder. Transpower planning includes a new 20 MVA transformer planned for 13/14 years.	169k in yr2	Most cost effective solution.
		Network Option 1	Install expensive indoor switchgear.		
		Non Network Option	Transfer loads to proposed Tangiwai supply in times of constraint.		
		Do Nothing	Possible faults due to conductor stress through overheating.		

TABLE 5-45: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO OHAKUNE POS

OHAKUNE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
OHAKUNE TOWN	Cumulative Capacity	Feeder Development	FED414	Install underground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm^2 Al XLPE	103k in yr9
	Hazardous Asset Renewals	Switches (Hazard)	6321	6321 Install RMU to remove 3 cables from pole in Ayr Street and two cables fused off this switch. This will supply 20L61, 20L59 and 20L60.	45k in yr1
			20L15	20L15 Upgrade transformer to transformer with RTE.	45k in yr2
			20L18	20L18 Install switchgear.	45k in yr6
			20L50	20L50 Upgrade transformer to include RTE.	45k in yr1
			20L59	20L59 Install transformer with RTE switch.	45k in yr4
			20L68	20L68 Install additional switchgear.	90k in yr4
			T4199	T4199 Install switchgear.	45k in yr7
TANGIWAI	Reliability	Switches (Reliability Improvement)	6118	6118 Automate to TLC's current Network Standards.	45k in yr5
			5673	5673 Automate switch.	23k in yr1
	Hazardous Asset Renewals	Switches (Hazard)	09R11 20L43 20L44 20L45 20L46	Install switchgear.	45k in yr6 45k in yr4 45k in yr6 45k in yr5 45k in yr7
		Low and Hazardous Two Pole Structures	20L06	20L06 Replace structure with ground mounted transformer.	62k in yr4
			20L21	20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	56k in yr14

OHAKUNE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
TUROA	Reliability	Switches (Reliability Improvement)	5680	5680 Automate to TLC's current Network Standards.	45k in yr5
			6356	6356 Switch Automation.	23k in yr1
			5695	5695 Automate to TLC's current Network Standards.	45k in yr9
	Cumulative Capacity	Feeder Development	415-01	415-01 Upgrade Cu 16mm^2 Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.	53k in yr5
			415-04	415-04 Redesign over LV and HV configuration for Rangataua. Check loading of all transformers including 20M09. Work in association with planned change of two pole structures 20M07 in 12/13 year and 20M08 in 13/14. Assess LV wire size and extending LV. Work to alleviate Low voltage problems and possible development of empty sections. Do stage two in 12/13 and part in year 16/17.	84k in yr1 84k in yr5 (Stage two)
			415-04	Wire upgrade 20/21 along Miro Street to strengthen feeder tie – conductor strength needs increasing to accommodate snow loading.	567k in yr9
	Hazardous Asset Renewals	Hazardous Underground Refurbishment	FED415	FED415- Cable protection as required. The cable beside the road to the ski fields is inadequately protected in places.	68k in yr10
		Switches (Hazard)	17N01	17N01 Install Switch Gear.	45k in yr9
			17N02	17N02 Install Switch Gear.	45k in yr10
			17N04	17N04 Need a visual break & earths Switch gear needed.	45k in yr3
		Low and Hazardous Two Pole Structures	20K09	20L09 Ground mount with 100 kVA transformer.	45k in yr15
			20L19	20L19 Construct to TLS's current Network Standards.	79k in yr8
			20L31	20L31 Construct to TLS's current Network Standards.	79k in yr6
			20M01	20M01 Construct to TLS's current Network Standards.	51k in yr7
			20M07	20M07 Ground mount transformer. Check loadings.	56k in yr5
			20M08	20M08 Ground mount transformer. Check loadings.	56k in yr2

TABLE 5-46: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO OHAKUNE POS

5.6.1.8 Voltage Regulators Installs in the Development Plan to Counteract Voltage Constraints

As stated in other sections TLC's network analysis package has been built out to expected loadings in 2026/27. This exercise has identified a number of legacy and future voltage constraints. These constraints, present and predicated, have been caused by both legacy issues and future cumulative capacity load growth.

The analysis models have been developed based on assumptions for critical issues such as power factor and reactive power flows in line with present measurement and expectations. If demand based charges are more successful than predicted, some of these installation may be delayed.

The proposed voltage regulator sites often need further investigation after the initial network analysis is carried out, for example SWER systems are difficult to model correctly and further field tests are often required.

The results of these checks and annual review of load growth may alter the timing of proposed voltage regulators in future AMPs. The Ongarue feeder proposed regulators may have to be brought forward in the planning cycle for 2013/14 AMP plan after further field tests are carried out and checks made on the SWER system loadings and to ensure there are no imbalances in the loading of the phases on the three phase system prior to the SWER systems.

The regulator expenditure has been allocated to the cumulative capacity expenditure category. Once many of the relays are upgraded to advanced meters in the northern area it may be possible to substitute some of the regulators for slightly less expensive capacitor banks. A major driver for needing to install the regulators is the need to comply with the 2010 Electricity (Safety) Regulations. Table 5-47 lists the voltage regulators included in the plan for 11 kV lines. (A number of regulators included in the sub-transmission system have been included in earlier sections.)

11 kV REGULATORS (Cumulative Capacity Allocation)			
Supply Point	**Feeder**	**Planning Notes for Voltage & Quality of Supply Improvements**	**Year and Cost Estimate**
HANGATIKI	Caves	Depends on tourism growth in area.	96k in yr13
	Gravel Scoop	Otewa Road just before Barber. Will mainly be used when back feeding to Rangitoto and Maihiihi feeders.	96k in yr14
	Hangatiki East	Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	96k in yr15
	Mahoenui	Mainly for backup of Mokau Feeder when 33 kV is out.	96k in yr8
	Maihiihi	Replace Whibley Road Regulator. This is an old type of regulator and overloads when back feeding.	96k in yr4
	Mokau	Before Mokau at old killing house site.	101k in yr7
	Mokau	Near Bolts place on top of hill.	101k in yr4
	Mokauiti	Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	96k in yr9
	Piopio	Prior to Piopio Township.	96k in yr8
	Rangitoto	Regulator towards Otewa Rd also to pick up Otewa when working on Gravel Scoop and Waipa Gorge.	96k in yr5
OHAKUNE	Tangiwai	Assumes new Tangiwai Supply from Transpower; locate at Rangataua.	107k in yr6
	Turoa	Regulator at start of Station Road.	107k in yr3

11 kV REGULATORS (Cumulative Capacity Allocation)			
Supply Point	**Feeder**	**Planning Notes for Voltage & Quality of Supply Improvements**	**Year and Cost Estimate**
ONGARUE	Matapuna	Install Regulator on Taupo Road to boost voltage for back feeds and customers further down Taupo Road.	96k in yr15
	Northern	By High School. Depends on load growth.	96k in yr10
	Ohura	One regulator for Ohura assuming that the coal mine venture goes ahead.	96k in yr9
	Ohura	Second Regulator assuming coal mine goes ahead.	96k in yr11
	Ongarue	Install Regulator at State Highway 4 near switch 6640.	96k in yr10
	Southern	Growth in dairying and irrigation along state highway. Just before Otapouri road. Will help lift voltage at Owhango for subdivision growth.	101k in yr14
	Western	Install regulator to accommodate increased load due to the subdivision of land for lifestyle blocks along River Road and the surrounding areas.	96k in yr11
WHAKAMARU	Huirimu	To hold up voltage with small conductor going east back to Pureora. Needs to be close to ABS 425.	101k in yr1
	Mokai	Install regulator on Waihora Road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	101k in yr5
	Mokai	Replace Tirohanga Road Regulator.	107k in yr13
	Pureora	Near switch 785 just after Ranganui Road on SH 30.	96K in yr12
	Pureora	Close to Crusaders Meats 4th Regulator for deer plant.	96K in yr6
	Whakamaru	Install regulator to lift voltage for irrigation pumps. Install near Kelly's Garage before the river crossing. Customer requires this.	101K in yr1
	Wharepapa	Install regulator on Hingaia Road near T299.	101K in yr2
	Wharepapa	Install regulator just after switch 376 on Whatauri Road.	101K in yr2

TABLE 5-47: VOLTAGE REGULATORS FOR VOLTAGE CONSTRAINTS

5.6.1.9 *Upgrades of conductor sizes in the Development Plan*

The overhead conductor upgrades listed in Table 5-48 are cumulative capacity upgrades as detailed in earlier sections. Additional conductor renewal pertaining to line replacement (as opposed to upgrade) have been included in the line renewal programme.

CONDUCTOR UPGRADE PROJECTS (EXCLUDING LINE RENEWALS)						
Feeder	**Asset**	**Conductor Size**	**Year**	**Constraint**	**Estimated Length**	**Estimated Cost**
Turoa	415-04	Mink	2020/21	Current & Voltage	5.5km	567k
Mokai	FED123	Mink	2013/14 2017/18	Current & Voltage	3.0km 7.0km	309k 721k

TABLE 5-48: PROPOSED CONDUCTOR UPGRADES FOR CUMULATIVE CAPACITY

5.6.1.10 Analysis of Distribution Transformers (larger sizes: 2 Pole Mounted: SWER and Ground Mounted) and Specific Locations where constraints are expected

The focus of the analysis of distribution transformers is hazard minimisation improvements. The results of this analysis have contributed to the lists of programmed work in the preceding sections.

5.6.1.11 Pole Mounted Transformers and Equipment (Distribution and SWER Isolation) Analysis

Historically, the structures for 2 pole distribution transformers and SWER isolation transformers were constructed low to the ground. All structures have been measured and assessed for hazards, including in particular, ground to live bare conductor clearances, and the ease of climbing up onto transformer mounting platforms. Other potential hazards such as the closeness of high voltage jumpers to low voltage fuse operating positions have also been considered.

The solutions include allowances for modifying the incoming and outgoing circuits to eliminate hazards and make the connections more straightforward and understandable by fault staff. The plan includes the on-going renewal of these structures starting from the worst. At this point TLC is about half way through the sites initially highlighted as hazardous. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period.

Sites were assessed for hazards using two independent parties. An electrical inspector viewed all photographs and prioritised. An engineer also went through the data and photographs allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan finalised. The timing of many of these renewals coincides with line renewal and other projects in the areas.

5.6.1.12 Ground Mount Distribution Transformer Analysis

The focus of the analysis of ground mounted transformers and enclosures, was to identify all security, operating, and potential points of contact with live terminal hazards. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period. Sites were assessed for hazards using two independent parties. An electrical inspector considered all photographs and prioritised. An engineer also went through the data and photographs, allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan was finalised.

5.6.1.13 Low Voltage System Underground and Overhead

The low voltage lines in the TLC network are of the same vintage as the 11 kV lines (old and in need of renewal). Many are well under current codes of practice height. The poles supporting many of these lines are often under strength and in poor condition. Most conductors are bare, and arcing, and clashing is common. This causes outages and the related surges may damage customers' equipment. The network has been analysed on an area by area basis and the renewal programme is summarised in the tables in section 5.7.1.

It is likely that aerial bundled conductor will be used for many of the renewals in rural villages. There are also poorly integrated underground and overhead systems that are creating hazards and require renewal to control these.

The design and planning process for each of these projects varies, being dependent on the local area issues. Low voltage renewal often involves customers' service lines and urban streets. As a consequence of this the design process involves discussions with landowners and road controlling authorities.

5.6.1.14 Underground Service Box Analysis

The constraint with low voltage service boxes is that they age and are subjected to vehicle and other damage. The result of this damage is that they often become insecure and the tops can be removed by members of the public. The damage is usually such that the service box needs to be renewed. The only other option is to leave them in a hazardous condition.

The option TLC chooses is to eliminate or minimise the hazard. Experience and evaluation of the service box stock shows that 50 p.a. need to be renewed out of the total stock of 3600 (approx. life of 60 years).

The cost estimate included for this work from years 2012 to 2027 is $101K p.a. An electrical inspector checks and tests service boxes on a five yearly cycle. Priorities are then set by this work. Refinements to the Basix system are currently being implemented to better manage and plan renewals of service boxes with respect to contractor priorities. Unless they are closely managed, service box renewals are treated with lower priorities and tend to 'slip off the radar'.

(Note: These renewals are not included in the tables above and are an output of the inspection programmes described in Section 6)

5.6.1.15 Analysis of Related Systems (Load Control, SCADA, Communication) and Specific Locations where constraints are expected

All related systems have been analysed and predicted future needs to meet customer service levels have been included in spend plans.

The load control system in the northern area cannot provide the required customer service levels without renewal. New plants were installed in the 2010/11 year. Plan 2012 includes relays that incorporate advanced meters over the years 2012/13 to 2018/19.

The estimates assume continuation of present strategies with SCADA. On-going and renewal and development of the SCADA equipment is included in forward estimates.

TLC's present voice radio network is an amalgamation of three networked repeaters across the northern area installed during 1997 operating to standards that remain current, with a network of three further repeaters based on older standards in the southern area. Late in 2009 New Zealand's radio licensing authority (Ministry of Economic Development, Radio Spectrum Management) advised this older standard (originally implemented in the 1960s) was to be phased out by 1 November 2015. This requires TLC to upgrade part of their radio system before the end of 2015, so this is an appropriate time to consider options for updating the overall radio network plus adding enhanced features.

TLC has included in its Plan a five year expenditure plan to upgrade the system. Table 5-49 lists the planned capital expenditure on load control, SCADA and communications equipment for the period 2012/13 to 2026/27. Provisions are expressed in current dollar value.

SUMMARY OF FORWARD EXPENDITURE PREDICTIONS FOR MISCELLANEOUS EQUIPMENT															
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Radio Specific	177,160	159,650	170,980	151,410	158,620	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644
Distribution Equipment	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275	56,275
Tap-offs with New Connections	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765	33,765
Load Control	0	0	112,551	0	0	0	0	112,551	0	0	0	0	112,551	0	0
Protection	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255
Radio Contingency	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255	11,255
SCADA Contingency	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883	16,883
Other Renewals	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA Specific	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644	41,644
Transformer Renewals	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653	337,653
TOTALS	685,889	668,379	792,261	660,139	667,349	550,373	550,373	662,924	550,373	550,373	550,373	550,373	662,924	550,373	550,373

TABLE 5-49: SUMMARY OF ESTIMATED FORWARD EXPENDITURE PREDICTIONS FOR LOAD CONTROLS, SCADA AND COMMUNICATIONS EQUIPMENT (WITHOUT INFLATION)

5.7 Description and Identification of the Network Development Programme 2012/13

This section covers the planned expenditure for capital projects under the following disclosure categories as listed in Table 5-50, along with the proposed expenditure for each category in the next 12 months.

CAPITAL EXPENDITURE PREDICTION SUMMARY - 2012/13	
Description	**Estimate**
Customer Connection	567,582
System Growth	1,043,142
Reliability, Safety & Environmental	1,374,105
Asset Replacement & Renewal - excluding Line Renewals	883,013
Asset Replacement & Renewal - Line Renewals	5,389,473
Asset Relocation	50,648
TOTALS	**9,307,963**

TABLE 5-50: SUMMARY OF CAPITAL EXPENDITURE PREDICTION 2012/13

5.7.1 Customer Connection Development Programme

5.7.1.1 Customer Connection Expenditure Predictions for 2012/13

Table 5-51 summarises the customer connection expenditure budgeted for projects planned for the next 12 months.

CUSTOMER CONNECTION - CAPITAL EXPENDITURE PREDICTION 2012/13	
Description	**Estimate**
General New Connection Contributions	318,270
Subdivision New Connection Contributions	111,395
Industrial New Connection and Unallocated Contributions	137,917
Specific Modifications Associated with Customer Development	0
TOTAL	**567,582**

TABLE 5-51: CUSTOMER CONNECTION CAPITAL EXPENDITURE PREDICTION 2012/13

5.7.1.2 Customer Connection Project Details

5.7.1.2.1 General New Connections Contributions - $318,270

This allowance is to fund distribution equipment costs associated with new customer connections and includes transformers and fusing at the connection point and other costs. This amount covers the cost of TLC's contribution to new connections. Generally, TLC has a policy of supplying a transformer and substation (including earthing) as its economic contribution to a new connection. These items are included in TLC valuation registers.

The investment is recovered by each customer's low voltage capacity or dedicated transformer charges. Continuing with the present policy of providing customers with transformers and assuming the predicted numbers of new connections means an allowance of $318,270 has been included.

The amount of the allowance expended is dependent on the number of new connections. Customer connections for 2011 are starting to increase after a slump starting in 2008 and bottoming out in 2010. See Graph 5-4 "Applications for Connecting Load onto TLC's Network" (Section 5.3.2.1.2), which indicates the trends in load applications onto TLC network.

Alternative options

The TLC charging structure means that customers have initial and on-going incentives to minimise the capacity of their connection assets by reducing peaks and using non-asset solutions.

A number of the dairy conversions are in areas where there is only a single phase supply. They have used the available supply for vat cooling and generators for milking.

The asset related charges are also arranged to maximise connection asset utilisation. The best way to achieve lower charges is to increase the amount of controllable load and the number of installations connected to a transformer. The non-network approach for customers is to do without load through control periods or use alternative sources of energy.

Another option for TLC would be to charge customers an increased contribution for new connections. This would mean that TLC would then have to charge a lower amount as part of on-going asset related charges. This option is available to customers and a number have opted to supply or fund their own transformers and earthing.

5.7.1.2.2 Subdivision New connection Contributions - $111,395

Scope

TLC supplies transformers and substation components as its capital contribution to new subdivisions. The developer funds the remainder. The substation components are those defined in the 2006 Valuation handbook. The amount of the allowance used is dependent on the number of new subdivisions and the allocation has been reduced due to the downturn in lifestyle and holiday home demand.

It is not possible to provide further detail on the proposed subdivisions until the subdivisions are being constructed. There are a number of small lifestyle subdivisions in the Otorohanga area and Ohakune has seen a number of applications for small residential subdivisions. However, most of these may be supplied from the existing infrastructure.

There are one or two sub-dividers that have applied for resource consent for large subdivisions, but at this stage they will not be developed until there is stronger economic confidence.

Alternative options

The alternative option available to reduce this cost is to install the smallest transformer possible. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity and reduce peaks. The charging structure also encourages the connection of more than three ICPs per transformer.

Most of the subdivisions that have gone ahead in 2011 have connected to existing infrastructure; TLC expects this to change as business confidence improves.

5.7.1.2.3 Industrial New Connection Contributions and Unallocated Contributions -$137,917

Scope

TLC supplies various items and recovers these as part of on-going charges to customers when expansions and alterations are taking place. No firm commitment has been made at this time. The known projects have gone on hold; however, one limestone quarry operator is still planning to install value added plant to increase their operations. The amount of the allowance used is dependent on the level of industrial development.

Alternative options

The alternative options available to reduce this cost include installing the smallest transformer possible and supplementing with other energy options. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity, reduce peaks and improve power factor. Alternative options for customers include providing energy requirements from alternative sources or providing their own transformers and earthing. Modular substation funded by the customer could be considered.

5.7.1.2.4 Specific Modifications Associated with Customer Development - $0.00

There is no allocation in this financial year. The specific needs of large customers are unknown at this time.

5.7.2 System Growth Development Programme

5.7.2.1 System Growth Expenditure Predictions for 2012/13

Table 5-52 summarises the cumulative capacity expenditure budgeted for projects planned in the next 12 months.

SYSTEM GROWTH - CAPITAL EXPENDITURE PREDICTION 2012/13	
Description	**Estimate**
Take new supply from Tangiwai GXP	463,500
Install regulators on 33 kV line to boost voltage from Atiamuri	281,381
Atiamuri Supply Point Transformer Cooling	11,255
Rangataua Township	84,414
Install regulators on 11 kV Huirimu Feeder	101,296
Install regulators on 11 kV Whakamaru Feeder	101,296
TOTALS	**1,043,142**

TABLE 5-52: SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTION 2012/13

5.7.2.2 System Growth Project Details

5.7.2.2.1 Tangiwai Supply Point- $463,500

Scope

Ohakune POS is at maximum capacity through the winter months. To alleviate this supply constraint TLC has negotiated with Transpower to connect to the 11 kV bus to take up to 200 amp feeder supply from the bus at Transpowers Tangiwai substation.

Due to the higher fault level at this point than TLC's network is capable of operating at, a fault reducing transformer and voltage regulators are required to reduce the fault levels. This installation includes a ripple injection plant to allow TLC to use demand side management load controlling.

Justification:

The project is presently being discussed with customers and the capital value is such that it will drive a 3-4% increase in customer charges. At the time of writing customers are unsure if they are prepared to accept this increase.

Transpower have recently agreed to install a new transformer at the GXP that will drive customer charges by 0.5%. Customers have agreed to this.

This decision leaves two further issues. These are:

- What to do between now and the larger Transpower transformer.
- What to do if customers do not want to accept the annual 8 hour Transpower maintenance shutdown.

Research has shown that the lowest cost option to satisfy both of these requirements is to take supply out of Tangiwai.

A recent customer consultation meeting resolved that consultation with a wider group of customers is required to better determine views.

The allowance has been included in estimates and draft designs have been completed; however the project will be delayed until the results of this customer feedback is known.

Transpower have issued warning to TLC about the level of off take from Ohakune substation through the preceding two winters. The new supply point from Tangiwai is the most cost effective solution for temporary capacity and provides a back feed options for Ohakune Town.

Alternative Options:

The alternative option is to upgrade Ohakune to full n-1; however, this would be a more expensive option as pricing indications show that Transpower connection charges would double.

5.7.2.2.2 Regulator on 33 kV line from Atiamuri - $ 281,381

Scope

This line was originally constructed as a 50kV transmission line. Purchased by TLC in 2002 and has since been operated at 33kV. As part of the conversion process, the conductor was changed and smaller 33kV insulators fitted.

When the supply from Whakamaru is unavailable TLC relies on the supply from Atiamuri. The Atiamuri generation bus voltage is only about 10.5 kV and, as a consequence, by the time supply travels about 70kms to Arohena it is below the tapping range of the Arohena transformer. A 33kV regulator is the most cost effective way to boost this voltage back to normal. The regulator will boost the voltage sufficiently to enable the tapping range on the transformers at the zone substations supplied by this 33 kV line to provide an acceptable voltage to the 11 kV feeders.

Justification:

The voltage is getting down to a level that would make it below regulatory limits (about 15% below regulatory limits in the worst case).

Alternative Options:

- Hire backup generation support to help support the voltage, but this can be an expensive option with no long term benefit from the expense.
- Install capacitors; however, these will interfere with the present ripple signal.
- Wait for the proposed generation to connect to the Pureora feeder; this does not solve the problem in the immediate future.

5.7.2.2.3 Atiamuri Supply Point Transformer - Cooling - $11,255

Scope

This project has two steps

1. Year 1 - SCADA upgrade to include information regarding the transformer temperature.
2. Year Two - Install cooling fans.

In year two if the SCADA data indicates that the need for fans is not required than step two will be removed from the planning.

In year 2022/23 TLC has programmed a transformer upgrade for this site. This work is a cost effective solution to allow the existing transformer to remain in service until its upgrade.

Justification

Collection of data will give TLC's planners better direction. This is the most cost effective solution and maybe modified in the long term plan if required. This transformer is in a critical location and it is often required to provide alternative supply backup. In these situations, it is called on for short term capacity at the upper end of its capacity rating. The controller needs accurate transformer temperatures at these times so better objective calls can be made on the implication of pushing this capacity. The cost of putting a second transformer into the site is significant as is the cost of failure of the present unit.

Alternative Options

The site could be left as is and the transformer could overheat reducing its life.

5.7.2.2.4 Redesign the layout of the HV and LV connections in Rangataua- Stage 1 - $ 84,414

Scope

This is a staged redesign of a growing township that has long LV runs that has been brought forward in the plan. There is planned work for a transformer upgrade in year 2012/13, which this redesign is to align with to improve voltage levels to customers on the LV. A conductor upgrade may be required or an additional transformer may be required once a study of the township and the LV runs is completed.

There is a second transformer structure programmed for replacement in 2016/17 and the final stage of the development is also programmed for that year.

Justification:

The voltage is getting down to a level that would make it below regulatory limits and customers are complaining about voltage dips.

Alternative options

There is no alternative option to providing acceptable voltage to customers.

5.7.2.2.5 11 kV Regulator on Huirimu Feeder - $101,296

This is a dairy farming area that historically was sheep and beef. The original conductor is of a smaller wire size and re-conductoring has been programmed into the plan when the next renewal cycle covers this area.

Voltage regulators are a cost effective method of lifting the voltage on the feeder to alleviate the voltage problems. This is a legacy voltage issue that has to be addressed for compliance.

Justification:

The voltage is getting down to below regulatory limits.

Alternative Options:

- Re-conductoring, which is a costly process as most structures will need to be replaced to carry the heavier wire. (About 15km would need to be re-conductored at about $100k per kilometre). Re-conductoring the first section from the zone substation at Arohena is programmed for year 2019/20.
- Install capacitors; however, these will interfere with the present ripple signal.
- Modular substation - this could only be justified if the load growth is greater than predictions.
- Wait for proposed generation that is to connected onto an adjacent feeder; this is not a realistic solution as the generation is run of the river.

5.7.2.2.6 11kV Regulator on Whakamaru Feeder - $101,296

A large irrigation project is planned for 2012/13 that will affect the voltage level of customers beyond the irrigation scheme especially near the end of the Whakamaru Feeder. By installing voltage regulators, models show that this will alleviate the problem.

Voltage regulators are a cost effective method of lifting the voltage on the feeder.

Justification:

The voltage is getting down to below regulatory limits.

Alternative Options:

- Install a modular substation connecting onto the 33 kV line that passes through Whakamaru area; this is programmed for later in the planning period to help load growth if more irrigation schemes are planned for the area.
- Reconductor with larger conductor; this is an expensive option; lower cost in the long term would be to install a modular substation. (About 10km at $100K per Kilometre would be required.)
- Install capacitors; however, these will interfere with the present ripple signal.
- Wait for proposed generation that is to connect onto an adjacent feeder; this does not fix the immediate problem.

5.7.3 Reliability, Safety and Environment Development Programme

Table 5-53 summarises the capital expenditure budgets for reliability, safety and environmental development for the next 12 months.

RELIABILITY, SAFETY AND ENVIRONMENT - CAPITAL EXPENDITURE PREDICTION 2012/13	
Description	**Estimate**
Reliability & Security	247,612
Hazardous Equipment Renewals (Safety)	1,070,215
Environmental Projects	56,278
TOTAL	**1,374,105**

TABLE 5-53: RELIABILITY, SAFETY AND ENVIRONMENT CAPITAL EXPENDITURE PREDICTIONS FOR 2012/13

5.7.3.1 Reliability & Security

Programme Objective

The objective of the reliability improvement programme is to bolster reliability and reduce operating costs. Staffing rural depots is expensive and providing efficient workflows for periods when faults are not occurring is difficult. Increased skills specialisation is adding to this difficulty. Network automation speeds restoration and takes away the need to maintain high staffing levels in rural depots to service faults.

The use of mobile generators and reactive voltage support units also provide a practical way of increasing network reliability and security.

The risk assessment analysis in Section 7 indicated that the contingencies are needed for new and end of lifecycle equipment. The ability to support the network with a generator during fault conditions and maintenance projects improves the reliability of the supply to customers, reducing unacceptable outages and producing a saving in customer minutes. Mobile reactive power units are a lower cost way of doing this.

Automation Options

TLC has numerous sites that will give customer benefits in the 5 to 15 cents per customer minute range. These sites have been identified and laid out in the Plan outlined in earlier sections.

There are options for the automation programme. These include:

- Delaying the overall programme.
- Completing works in conjunction with other works and network development in the area.
- Targeting the worst areas.

The option selected is a combination of the latter two. (Targeting worst areas and completing works in conjunction with other projects in the area.) The reliability programme has been set at about $250,000 p.a. Experience to date has shown that this level of expenditure can be accommodated by the organisation and generates an on-going customer benefit through the network. (This current year has less expenditure allocated to allow for the high cost of creating a new POS in Ohakune as detailed earlier.) The automation of breakers improves network outage statistics, and has a hidden benefit in that it provides better data for on-going network analysis, including revenue reconciliation, and reduces operating costs.

Projects are aligned with the need to meet reliability objectives and service level standards as detailed in earlier sections. The last customer survey also highlighted customers' expectations of continuously improving supply reliability. The overall long term reliability target, however, remains the same and TLC recognises that it is important to achieve this target.

In recent times attracting staff to rural areas and meeting the costs of retaining these people to cover standby rosters have become difficult issues. Three of TLC's rural depots (Ohakune, Turangi and Whakamaru) no longer have enough staff to cover full rosters and the areas have to be covered on alternative weeks (solo staffed depots are normally on a 1 in 2 roster). This means at least a two hour mobilisation delay for the weeks when there is no local cover.

Table 5-54 lists the Reliability and Security projects planned for the next year.

RELIABILITY & SECURITY - 2012/13 PROJECTS AND CAPITAL EXPENDITURE PREDICTIONS		
Feeder	**Activity**	**Cost Estimates**
Turangi	Automate 6191	56,275
Turangi	Automate 5208	56,275
Raurimu	Install new recloser	56,275
Turoa	Automate 6356	22,511
Mokai	Automate 493	33,765
Tangiwai	Automate 5673	22,511
TOTAL		**247,612**

TABLE 5-54: SUMMARY OF FEEDER PROJECTS FOR RELIABILITY & SECURITY

5.7.3.1.1 Turangi – Automate Switch 6191 - $ 56,275

Scope

This switch is the tie point between Turangi Town and Hirangi Feeders. There is an existing Magnefix switch that will need replacing with a 3 bay Xiria switch. The Magnefix can be reused at other sites in the network.

Justification:

In fault situations, customer minutes can be reduced quickly by back-feeding sections of Turangi's business and residential areas. There are potentially eleven transformers in the Turangi business area that could be back-fed from the Hirangi feeder or, alternatively, seven residential transformers that could be back-fed from the Turangi feeder.

Table 5-54a lists the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TURANGI 6191 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	750
Annual estimated reduction in outage minutes	B	90
Project costs	C	$56,275
Annual cost inclusive of finances, maintenance etc	D	$9,000
Annual direct cost savings (contractors time to operate switches etc)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.13

TABLE 5-54A: RELIABILITY BENEFIT CALCULATION – TURANGI 6191

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. The project is integrated with asset 5208 (following item) and needs to be done in conjunction with this.

Alternative Options

The site could be left as a manual switch with no automation. However, in an after hours situation on alternate weekends, a fault-man may have to travel from Taumarunui, which is 60 minutes away, to restore power should a fault occur. This may extend to 90 minutes including establishment times.

5.7.3.1.2 Turangi - Automate switch 5208 – 56,275

Scope

This is the site where the overhead line becomes underground. An old pothead termination is in need of replacement, and has caused problems in the past.

Install a 4 bay 11 kV Xiria switch at tap-off 5208 to supply Turangi and have a parallel with Rangipo/ Hautu Feeder.

Justification

This will give an alternative option to back feed the CBD of Turangi town along with the automation of 6191 detailed above. Further saving will be made by allowing the control room to remotely control the switch and speed fault finding if there is a cable fault in the Turangi area.

Table 5-54b gives the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TURANGI 5208 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	2000
Annual estimated reduction in outage minutes	B	90
Project costs	C	$56,275
Annual cost inclusive of finances, maintenance etc	D	$9,000
Annual direct cost savings (contractors time to operate switches etc)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.05

TABLE 5-54B: RELIABILITY BENEFIT CALCULATION – TURANGI 5208

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. The project is integrated with asset 6191 (previous item) and needs to be done in conjunction with this.

Alternative Options

As with the other reliability projects, the site could be left as is. This project is part of TLC automation projects to decrease customer outage times and is integrated with project 6191 (previous item).

5.7.3.1.3 Raurimu Feeder – New Recloser - $56,275

Scope

The Raurimu feeder has a long spur line that supplies electricity to Kaitieke, Whakahoro, Retaruke and the Ruatiti areas. This line crosses rugged country and much of the line is hard to access. A recloser at the start of this spur line would allow Raurimu Township to be unaffected by faults beyond this recloser.

Justification:

Small businesses in Raurimu are affected by rural outages and most are operating in the winter when more outages occur. An improved level of service will be beneficial to these customers.

The installation of a recloser will allow quicker power restoration to more densely populated areas. Further saving will be made by allowing the control room to remotely control the switch and decrease the fault-man's travelling time when fault finding and sectionalising.

Table 5-54c lists the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

RAURIMU FEEDER RECLOSER: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	200
Annual estimated reduction in outage minutes	B	350
Project costs	C	$56,275
Annual cost inclusive of finances, maintenance etc	D	$9,000
Annual direct cost savings (contractors time to operate switches etc)	E	$300
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.124

TABLE 5-54C: RELIABILITY BENEFIT CALCULATION – RAURIMU FEEDER RECLOSER

The results lay in the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. This project is at the higher end of the cost per customer minute range but the site is physically significant. The proposed recloser site is at the junction of relatively accessible lines and a very inaccessible section. This inaccessible section runs along a particularly steep and rugged ridge line for about 10 kms, and even with a helicopter is difficult to access. The recloser will isolate this away from the more densely populated sections of the feeder asset groups.

Alternative Options

The site could be left as it is. This would mean that TLC would not be able to meet its target service level and improve Network performance.

5.7.3.1.4 Turoa Feeder - Automate ABS 6356 - $22,511

FIGURE 5-23: ABS 6356

Scope

The project involves automation of an existing manually operated switch. The existing site, as shown in Figure 5-23, has a new pole and switch; therefore the most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

This is a tie switch between the Turoa and Tangiwai feeders. The switch can be used for back feeding and, as the area is covered by a sole fault-man, in fault situations, the control room personnel operating the switch can speed up restore times. These improved restore times will improve service to both the ski fields and the busy tourist sections of the town.

Table 5-54d gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TUROA 6356 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	700
Annual estimated reduction in outage minutes	B	60
Project costs	C	$22,511
Annual cost inclusive of finances, maintenance etc	D	$3,800
Annual direct cost savings (contractors time to operate switches etc)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.08

TABLE 5-54D: RELIABILITY BENEFIT CALCULATION – TUROA 6356

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. This project is another cumulative step in improving services to Ohakune given that the area is covered by a single fault-man and at the height of the tourist season, there are a large number of people in this area.

Alternative Options

The site could be left as it is. This would mean that TLC would not be able to meet its target service level and improve Network performance.

5.7.3.1.5 Mokai Feeder – Automate 493 - $33,765

Scope

Automation of this switch will allow the Controller to speed up restoration to one section of Whangamata Road where there are a number of dairy farms connected. A tree problem beyond switch 493 has meant that automation closer to the zone substation has to be used to restore electricity to the healthy parts of the feeder, until a fault-man can operate the manual ABS. A new site repeater may be required if there is no communication signal at site 493.

At either a new site or the existing site a new pole, RTU aerial and vacuum 11 kV ENTEC switch will need to be installed.

Justification

Beyond switch 493 TLC has battled with an on-going tree problem in the area. The travelling time to this site is about 1½ hours. The automation of this switch will assist in reducing fault-man travelling time that will lower fault restoration times.

Table 5-54e gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

MOKAI 493 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	300
Annual estimated reduction in outage minutes	B	240
Project costs	C	$33,765
Annual cost inclusive of finances, maintenance etc	D	$5,400
Annual direct cost savings (contractors time to operate switches etc)	E	$300
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.07

TABLE 5-54E: RELIABILITY BENEFIT CALCULATION – MOKAI 493

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. This project targets a repeated problem area in terms of plantation trees that affect a relatively large number of customers. It is about 40 minutes travel time from a solo manned depot and 2 hours from the nearest large depot. This equipment will allow the remainder of the feeder to be isolated and supply renewed.

Alternative Options

The site could be left as is.

5.7.3.1.6 Tangiwai Feeder – Automate 5673 - $22,511

Scope

Automation of this switch will allow the Controller to quickly isolate any faults that occur beyond this switch.

The most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

The switch supplies a remote rural area prior to Ohakune town and the town residential areas can be affected if a fault occurs in this section of the feeder. This feeder has a recloser on the eastern side of town to protect the denser populated areas from faults but between main supply from the Transpower substation and Ohakune township, there is no equipment to protect the township from faults on the rural spur that taps off and supplies rural areas along the Lakes Road area.

Further saving will be made by allowing the control room to remotely control the switch and decrease the fault-man's travelling time when fault finding and sectionalising.

Table 5-54f gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TANGIWAI 5673 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	500
Annual estimated reduction in outage minutes	B	60
Project costs	C	$22,511
Annual cost inclusive of finances, maintenance etc	D	$3,600
Annual direct cost savings (contractors time to operate switches etc)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.116

TABLE 5-54F: RELIABILITY BENEFIT CALCULATION – TANGIWAI 5673

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. This project targets a repeated tree problem area on a spur off the main line between the GXP and most of the connected customers. The site is about 10 minutes from a solo manned depot and 2 hours from the nearest large depot. This means every second weekend isolation times become significant. This equipment will allow the remainder of the feeder to be isolated and supply restored quickly by the TLC controller.

Alternative Options

The site could be left as is.

5.7.3.2 Hazardous Equipment Renewals (Safety)

Hazardous equipment renewals are included in the development section in accordance with the disclosure requirements for capital expenditure. The category includes renewals for reliability, safety and environmental reasons but does not cover line renewal.

A summary of hazard elimination/minimisation projects is given in Table 5-55

HAZARD REMOVAL / MINIMISATION - 2012/13 PROJECTS AND CAPITAL EXPENDITURE PREDICTIONS	
Projects	**Estimate**
Supply Points	67,531
Zone Substations	341,062
Feeder and Switchgear	135,060
Low and Hazardous Two Pole Structures	290,470
Ground Mounted Transformers	135,060
Pillar Boxes	101,032
TOTAL	**1,070,215**

TABLE 5-55: SUMMARY OF CAPITAL EXPENDITURE; HAZARD ELIMINATION/MINIMISATION PROJECTS

5.7.3.2.1 Supply Point Hazard Minimisation Projects

Table 5-56 shows the POS hazardous renewal programmed for 2012/23.

SUPPLY POINT HAZARD REMOVAL / MINIMISATION	
Point of Supply	**Estimate**
Tokaanu POS	67,531
TOTAL	**67,531**

TABLE 5-56: POINT OF SUPPLY HAZARD ELIMINATION/MINIMISATION PROJECTS

5.7.3.2.1.1 Tokaanu Supply Point – Install Switchgear - $67,531

Scope

The equipment located at the Transpower and Genesis Energy Tokaanu site includes a load control plant and 33kV switchgear. In the present configuration, there is a situation where there is no way of isolating some capacitors associated with a ripple injection plant without affecting large numbers of customers. The scope of the project is to install switchgear capable of breaking a capacitive circuit. A Sectos switch that is currently in stock can be used for this project.

Justification

The present configuration is a hazard for personnel who may be working on the lines and equipment downstream from the load control plant.

Alternative Options

The site could be left as is with the risk of hazards to staff.

5.7.3.2.2 Zone Substation Hazard Minimisation Projects

Table 5-57 lists the zone substation hazardous renewals planned for 2012/13.

ZONE SUBSTATIONS HAZARD REMOVAL / MINIMISATION	
Zone Substation	**Estimate**
Mahoenui Zone Substation Switchgear	67,531
Turangi Zone Substation	206,000
Turangi Zone Substation	67,531
TOTAL	**341,062**

TABLE 5-57: ZONE SUBSTATION HAZARD ELIMINATION/MINIMISATION PROJECTS

5.7.3.2.2.1 Mahoenui Zone Substation- Renew 11 kV Switchgear - $67,531

Scope

Circuit breaker and protection are getting old and need maintenance/renewal to be reliable. Replace the 11 kV circuit breaker with modern equipment to increase the functionality of the breaker.

Justification

The 11 kV breaker at the Mahoenui substation needs upgrading to ensure the protection operates reliably. If 11 kV protection does not operate there is risk of a fault, such as a line down should a car hit a pole, and the circuit not being isolated.

Alternative Options

There are no alternative options if we are going to have reliable protection at zone substations.

5.7.3.2.2.2 Turangi Zone Substation- Install Switchgear - $206,000

Scope

Add additional 33 kV Switchgear and protection equipment. Cable away from substation to remove 5 spans of double circuit 11 kV. Upgrade protection schemes to ensure primary and backup protection is reliable.

Justification

Present arrangement as it crosses between TLC and Transpower boundaries is complex, non-standard and consists of old components not designed for the job they are doing. The existing protection is not operating reliably meaning that there is a hazard control issue.

Alternative Options

The site could be left as is but it is a confusing configuration for staff to work on.

5.7.3.2.2.3 Turangi Zone Substation – Replace Fence - $67,531

Scope

Replace the substation fence, which is a hazard risk to the public.

Justification

This is the most cost effective solution and substation security is of importance to prevent unauthorised access.

Alternative Options

There are no alternative options if TLC is going to have reliable protection at zone substations.

5.7.3.2.3 Feeder and Switchgear Hazard Minimisation Projects

Table 5-58 lists the projects planned to minimise hazardous equipment for switchgear in the next year inclusive of engineering costs

FEEDER & SWITCHGEAR HAZARD REMOVAL / MINIMISATION - 2012/13		
Feeder	**Site**	**Estimate**
Ohakune Town	20L50	45,020
Ohakune Town	6321	45,020
Chateau	T4066	45,020
	TOTAL	**135,060**

TABLE 5-58: SUMMARY OF FEEDER SAFETY PROJECTS

5.7.3.2.3.1 Ohakune Town Feeder – Transformer 20L50 - $45,020

Scope

This transformer is daisy chained with two other transformers. Replace the transformer with one containing an RTE switch. This will allow isolation of two of the transformers.

Justification

The present transformer and daisy chained transformers cannot be isolated. This means that extensive outages are necessary to do relatively minor works. Experience has shown that staff, when faced with this situation, often take risks. The LV wiring is also hazardous and this project includes replacing this with improved switchgear. A by-product of this project will be improved reliability given that the transformers will be able to be more easily isolated.

Alternative Options

The site could be left as is, but this does not reduce SAIDI minutes and reduce hazards to staff and the public.

5.7.3.2.3.2 Ohakune Town Feeder – Ring Main Unit - $45,020

Scope

Install a RMU to remove 3 cables from pole in Miro St and two sets of 3 phase links; additional work is to remove low LV wires in associated work. Figure 5-24 illustrates the hazardous layout on this pole.

Justification

This pole has two sets of drop out fuses, 6176 & 6321, installed and three cables terminating on the pole. One set of drop-outs controls three transformers. The other set protects the main feeder cable. The back set of fuses are very difficult to access.

A RMU will give three phase switching for the feeder, as the location is at the end of a long run of cable, which could exhibit the phenomena of ferroresonance with single phase switching. The RMU will allow safer isolation of the transformers.

FIGURE 5-24: POLE WITH LINKS 6176 & 6321

Alternative Options

The site could be left as is; this does not achieve TLC's commitment to providing a non-hazardous environment for personnel to work in.

5.7.3.2.3.3 Chateau Feeder – Transformer T4066 - $45,020

Scope

This transformer is teed off the main ski field cable via a tee joint that has no provision for isolating the transformer. The installation of a Xiria 11 kV switch will allow hazard controlled isolation of the transformer and work on this transformer and its associated LV reticulation that will not affect the remainder of a major feeder.

Justification

Transformers connected without any form of isolation and limited protection into a major passing feeder is less than ideal. There is a risk that staff will push safety boundaries rather than isolating a large area during planned and unplanned works.

Alternative Options

The site could be left as is.

5.7.3.2.4 Two Pole Structure Hazard Minimisation Projects

Table 5-59 lists the projects planned to minimise hazardous equipment for two pole structures in the next year.

TWO POLES STRUCTURES - 2012/13			
Feeder	**Site**	**Scope**	**Estimate**
Northern	01A50	Rebuild structure 11 kV only 4m above ground. Ground mount transformer; if possible, use a second hand 100 kVA.	47,834
Northern	06H11	Raise equipment on structure; recloser assets only 3.75m above the ground.	47,834
Ongarue	04I01 & T4128	This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Check loading on both SWER isolating transformers as load flow program indicates transformers could be overloaded.	59,740
Oruatua	09U07	Replace with a ground mounted transformer. Pole requires replacing and LV runs through trees. Earth mat appears to be damaged.	67,532
Oruatua	09U10	Replace with ground mounted transformer on opposite side of road. Adjacent high wooden fence makes any structure a hazard.	67,532
		TOTAL	**290,470**

TABLE 5-59: TWO POLE STRUCTURE PROJECTS FOR HAZARDOUS RENEWAL IN 2012/13

FIGURE 5-25: TWO POLE STRUCTURE 09U10

Justification

These structures have been identified and prioritised for renewal given that they present hazards to staff and the public. They support equipment that is low to the ground, close to fences and the like, that can be climbed and are hazardous for staff to work on. Figure 5-25 illustrates an example of one of the structures included in this Plan for improvement. It can be visualised from the photograph that a person standing on top of the fence could touch or be very close to energised exposed terminals. The structure is located in a populated area; in this case in a holiday settlement on SH1 north of Turangi on the shores of Lake Taupo. Not illustrated in the photograph are the 11 kV fuses. These are difficult for a fault-man to access and there is a risk of his ladder falling into HV jumpers.

Alternative Options

Sites could be left as is; this does not achieve TLC's commitment to minimizing hazards for staff and public.

5.7.3.2.5 Ground Mounted Transformer Hazard Minimisation Projects

Table 5-60 lists the projects planned to minimise hazardous equipment for ground mounted transformers in the 2012/13.

GROUND MOUNTED TRANSFORMERS - 2012/13		
Feeder	**Site**	**Estimate**
Mangakino	T706	45,020
Turangi	10S31	45,020
Turangi	10S46	45,020
	TOTAL	**135,060**

TABLE 5-60: GROUND MOUNTED TRANSFORMER PROGRAMMED FOR HAZARD MINIMISATION IN 2012/13

5.7.3.2.5.1 Mangakino Feeder – Transformer T706- $45,020

Scope

This transformer is enclosed in a wooden structure and has open bushings inside the enclosure. Install a refurbished 200 kVA I tank transformer, and remove old structure.

Justification

The wooden structure has deteriorated and can be broken into. The enclosure is located in an area where vandalism is common. It is not difficult to remove the nailed wooden fence palings that protect the public from energised 11 kV jumpers. A double locked I tank transformer will substantially improve security.

Alternative Options

The site could be left as is.

5.7.3.2.5.2 Turangi Feeder – Transformer 10S31- $45,020

Scope

The transformer along with a Magnefix in located in a Tin shed on the road side. The transformer has open HV bushing. The pilot wire is in a poor state. The LV rack is open and located next to Magnefix.

Replace with an I tank transformer that can accommodate a Magnefix switch in the HV cubicle and replace the LV panel.

Justification

Working on the LV rack places staff close to the HV on the Magnefix. The wiring on the LV rack is messy and difficult to identify circuits. The tin sheds are not as secure as the I Tank type transformers.

Alternative Options

The site could be left as is.

5.7.3.2.5.3 Turangi Feeder – Transformer 10S46- $45,020

Scope

The transformer along with a Magnefix is located in a tin shed. The transformer has open HV bushing and a low voltage panel that has substantial exposed energised metal. The scope is to replace the transformer with an I tank unit that can house the Magnefix equipment. The low voltage panel also needs replacing with enclosed LV switchgear.

Justification

Figure 5-26 illustrates the present unit. It can be seen that there is a substantial amount of energised exposed metal. There have been a number of alterations taken place over the years that have resulted in fuses being removed and the pilot system is confusing.

Alternative Options

The site could be left as is.

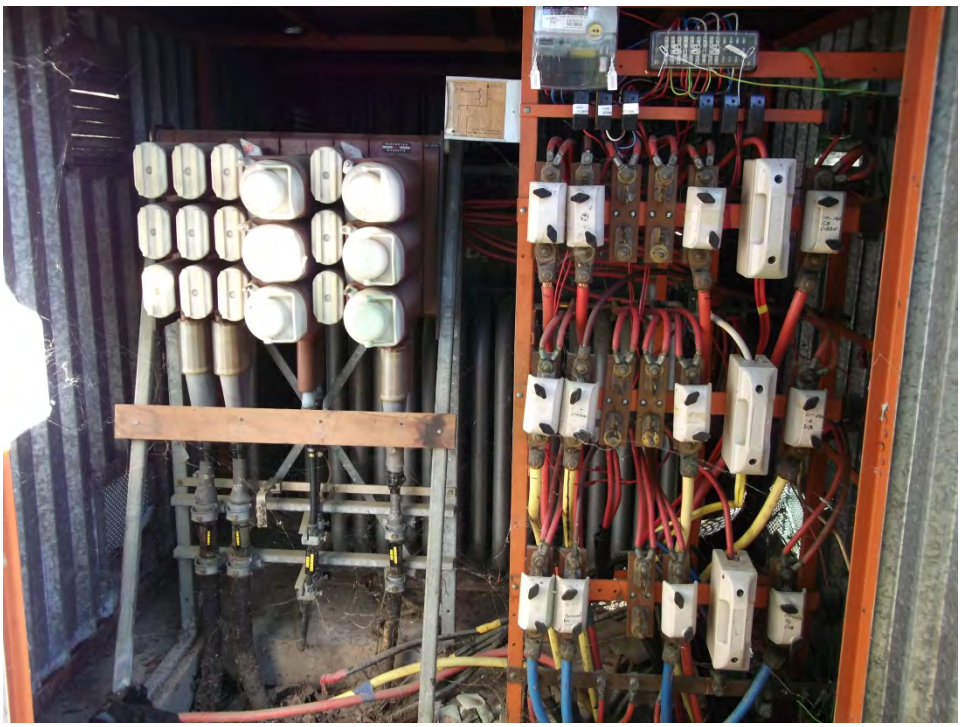


FIGURE 5-26: TRANSFORMER 10S46 LV RACK AND MAGNEFIX

5.7.3.2.6 Pillar Box Hazard Minimisation Projects

There are 48 sites planned for renewal in the 2012/13 year at an estimated cost of $101,032.

TLC owns 4020 pillar boxes; these pillars are inspected every 5 years. Those pillars that do not comply with TLC's current standards are programmed into the renewal programme, which targets the worst of the pillar boxes first. These pillars are renewed with a ground mounted pillar that can be padlocked or, if the location of the pillar is one that is repeatedly struck by vehicles, then a flush type pillar is selected.

5.7.3.3 Environmental Projects

This section covers capital expenditure on equipment upgrades associated with meeting environmental requirements. Table 5-61 summarises the planned expenditure for the next 12 months.

ENVIRONMENTAL PROJECT EXPENDITURE 2012/13		
Environmental Renewal Projects	**Scope**	**Estimate**
Waitete Zone Substation	Modify and install oil bunding, oil separation and earthquake restraints.	28,139
Te Waireka Zone Substation	Modify and install oil bunding, oil separation and earthquake restraints.	28,139
	TOTAL	**56,278**

TABLE 5-61: SUMMARY OF PLANNED EXPENDITURE FOR ENVIRONMENTAL PROJECTS 2012/13

Neither of the two substations listed in Table 5-61 have earthquake restraints or oil bunding. TLC is progressively bringing all substations up to today's environmental standards.

Justification

This is a requirement for environmental protection.

Alternative Options

The site could be left as is. There are no non-network options available.

5.7.3.4 Other Asset Replacement & Renewal (Excluding Line Renewals) Projects for the 2012/13 year

Table 5-62 summaries the asset renewals and replacements planned for the next 12 months.

ASSET RENEWAL AND REPLACEMENT - 2012/13	
Projects	**Estimate**
Tawhai Zone Substation Transformer Refurbish	90,041
Equipment Renewals	685,889
Load Control Relays	107,083
TOTAL	**883,013**

TABLE 5-62: SUMMARY OF RENEWAL EXPENDITURE

5.7.3.4.1 Tawhai Zone Substation- Refurbish - $90,041

Scope

The project involves removal of the transformer for a period of approximately 6 weeks. During this time the unit will be de-tanked, dried and tightened. Oil test results are showing that provided it is serviced, the transformer will likely give further reliable service.

Justification

Cheaper than letting the transformer rundown and need replacing.

Alternative Options

Replace transformer.

5.7.3.4.2 Equipment Renewals - $685,889

Equipment renewals cover the following categories as in Table 5-63, which summarises the general non-specific individual equipment renewal contingencies.

EQUIPMENT RENEWALS - 2012/13	
Category	**Cost Estimate**
Tap-offs for new connections – Renewals bought forward	33,765
Radio Specific Renewals	177,160
Radio Contingency (Emergent)	11,255
SCADA Contingency (Emergent)	16,883
SCADA Specific Renewals	41,644
Transformer Renewals (Emergent contingency)	337,653
Protection Renewals (Emergent)	11,255
Distribution Equipment Renewals (Contingency)	56,275
TOTAL	**685,889**

TABLE 5-63: RENEWAL PROJECT FOR 2012/13

5.7.3.4.2.1 Tap-offs with new connections - $33,765

This is a contingency amount set aside each year for the installation of fuses on private line tap-offs or new connections. This protects the network from private line faults. It is a renewals bought forward allowance – i.e. If a tap-off pole needs to be replaced to facilitate a new connection, then TLC may contribute to this via this allowance if the pole was likely to be replaced as part of the next renewal cycle. It is considered unfair to expect a customer to fund the total renewal of a pole if it is in poor condition and likely to be renewed as part of the next cycle of the renewal programme.

5.7.3.4.2.2 Radio Specific - $177,160

TLC is upgrading is radio communication sites over a five year period. Initially TLC needs to comply with the regulations that have a deadline of 2015 of changing from 25 kHz bandwidth to 12.5 kHz bandwidth. The equipment that is used to achieve the upgrade is capable of switched between analogue and digital. An upgrade programme has been prepared by a communications consultant.

5.7.3.4.2.3 Radio Contingency - $11,255

This is a sum set aside per annum to cover any unforeseen capital work on the radio system. TLC owns and operates 20 repeater sites for data and voice communications throughout the network. Each of these sites contains various numbers of radios, batteries, chargers, aerials and other electronic equipment that need to be replaced on an on-going basis as the equipment ages. The data radio system is the backbone of network automation and in recent times there have been a lot of additional remote circuit breakers, substations and other controlled equipment added.

If the radio network fails, communication with various items of remote equipment is lost. When this occurs, load control inputs and signals cannot be sent and automated equipment cannot be communicated with. Potential cost increases come from loss of load control during peaks. When failures occur, various options are considered. The refurbish/renew decision is based on the policies and issues outlined in the preceding sections.

5.7.3.4.2.4 SCADA Contingency - $16,883

This is a sum set aside per annum to cover any unforeseen capital work on the SCADA system. TLC now has automation in some form at approximately 30 zone substations, a distributed generation site, 11 load control plants and about 70 field devices. In addition to operation of field devices the equipment provides the central summation function of system load, generation and dispatch of load control signals.

5.7.3.4.2.5 SCADA Specific – $41,644

This is work to ensure the SCADA system is using the latest software and computers. The organisation has two options with SCADA equipment: either maintain and renew it on an on-going basis or let it run its course and complete a total replacement at the end of the equipment life.

The equipment is at the heart of the operating of the network and the rundown option would have many negative flow-on effects as reliability decreases. Increasing SAIDI would be one of these effects plus increased costs from having to send staff to various sites. The option of maintaining the equipment in a reliable state is currently being followed.

5.7.3.4.2.6 Transformer Renewals $337,653

This is a contingency amount set aside for distribution transformer failure through lightning strikes or either damaged or old units that are uneconomic to refurbish.

This allowance also covers refurbishment of recycled transformers. The work completed as part of this covers painting and other tidying after about 20 to 30 years of service to allow the unit to run through to about 50 to 60 years of service.

5.7.3.4.2.7 Protection & Voltage Relays - $11,255

A contingency amount set aside per annum to cover any protection equipment failure. This contingency is to mostly renew but sometimes refurbish in service equipment on failure. The TLC network has about 150 relays plus a similar number of other tripping and alarming relays in service. Over the past few years a number have failed or been found to be working incorrectly.

5.7.3.4.2.8 Distribution Equipment – 56,275

A contingency amount set aside per annum to cover any protection equipment failure. TLC owns, and still has in service, some very old switchgear, regulators and other distribution equipment. From time to time units fail and parts to repair this equipment are no longer available. When these events occur, the purpose of the equipment is reviewed and if it is still needed it is replaced with a modern equivalent.

5.7.3.4.3 Load Control Relays - $107,083

One of the weaknesses identified in the constraints section and in earlier AMPs was the implications of old high frequency ripple injection into the Hangatiki and Whakamaru supply points. A full report was put to Directors in July 2008 and they approved the plant renewal in the 2009/10 programme.

The report included a full discussion of operational and financial evaluation. In summary the conclusions were:

- That reliable load control and demand based charges would not be possible without renewal.
- All smart metering solutions deployed to date in New Zealand have continued to use load control systems.
- The long term financial benefit of replacing the plants outweighed the option of not renewing.
- The best technology option was to replace the existing system with a lower frequency ripple system.

The new load control plants are in place and the programme now moves onto relay replacement. It is envisioned that the programme will continue for the next 7 years.

The load control replacement programme was originally planned to start in the 2010/11 year; however, this was delayed due to the intent to combine it with TLC's advanced meter programme rollout. The cost of advanced meters which now include load control relays are such that the installation of a combined unit is similar to that of a legacy relay.

Advanced meter firmware has now been developed to the point that it will read both retailer and TLC demand based charging data and includes the capabilities for future communications and in-home displays.

The year 1 (2012/13) allowance is to roll out a number of units and test the technology. The allowance included in this Plan is based on the amount it would cost to replace the relays. It is based on a model of a typical relay replacement programme and will forma contribution to the meter rollout; the numbers and costs are not fully funding the meter rollout.

Justification and Scope

TLC requires meters that will operate with the load control signal of the new ripple plants 317Hz decabit signal, which will improve TLC's ability to use demand side management load control.

The network must fund the renewal of relays and the associated administration systems to control these assets. The metering on the network is also substantially owned by a subsidiary company. These meters largely need recertification and renewal under the Electricity Authority's rules. There are about 5500 relays in the northern area that are affected by the load plant change out.

For the purpose of planning, the relay exchange cost of $210 per relay inclusive of administration has been included in estimates. The estimates are as follows in Table 5-64.

RELAY RENEWAL PROGRAMME		
Year	**Number of relays**	**Estimated cost exclusive of inflation**
Year 1	500	107,083
Year 2	1500	309,993
Year 3	1500	309,993
Year 4	1500	309,993
Year 5	300	66,501
Year 6	150	36,064
Year 7	50	15,773
	TOTAL	**1,155,400**

TABLE 5-64: RELAY RENEWAL PROGRAMME

Alternative Option

The alternative options include:

- Not replacing relays and allow the effectiveness of the load control plant to reduce.
- Replacing the mains signal load control system with some other system. Analysis of options has shown that the lowest cost and most effective option is to replace the system with lower frequency load control equipment.

Non Asset Solution

The objective of load control and network constraint signalling is to create the opportunities for non-asset solutions. A non-asset solution may have been to go to some other form of signalling but, at the time the decisions were made, there were no alternative technologies that could provide reliable and effective load control for the TLC network.

5.7.4 Asset Replacement & Renewal - Line Renewal Expenditure for the next 12 months

The line renewal capital expenditure is primarily associated with replacement and refurbishment of existing lines. This work is to maintain the network and equipment to meet target levels of service.

Section 6 covers full details of the line renewal expenditure as summarized in Table 5-65.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL CAPITAL EXPENDITURE PREDICTION - 2012/13	
Project	**Estimate**
33 kV Line Renewal (includes emergent)	451,106
11 kV Line Renewals (includes emergent)	4,719,557
LV Line Renewals (includes emergent)	218,811
TOTAL	**5,389,473**

TABLE 5-65: SUMMARY OF LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS

5.7.5 Asset Relocation Development Programme

This expenditure is primarily associated with relocating assets for road controlling authorities to carry out road works. The amount spent depends on the locations of road works.

A contingency allowance of $50,648 has been included in estimates for 2012/13.

Note: This expenditure may be varied due to the changing legislation for access to railway and road corridors.

5.8 Summary Description of the Projects Planned for the next 4 years (2013/14 to 2016/17)

5.8.1 Unknowns

The unknowns that will affect plans are:

- Distributed generation development - which schemes will go ahead is unknown.
- Customer development - rural, residential, industrial and ski field.
- Network unknowns - An aged network will have unplanned and unexpected problems.
- Project unknowns - weather, landowners, resource shortage, access, and other factors will affect projects.
- Industry issues - compliance etc.
- Customers' ability to pay increased charges to fund the renewals.
- Political and other influences such as economic cycles.
- Other events unknown at this time. (e.g. natural disasters)

The estimates will be influenced by levels of economic activity and future energy prices. For example, there are unknowns with the distributed generation proposals and the network upgrades that would be required to connect this plant. The economics of wind farms appear to be marginal and as a consequence of this the commercial negotiations are taking some time to resolve. This has resulted in the transfer of predicted expenditure in earlier plans into years further out. Similarly the resource consent process has slowed a number of proposed hydro developments.

5.8.2 Summary of Expenditure Predictions 2013/14 to 2016/17 in disclosure categories

A summary of the disclosure categories expenditure predictions (without inflation) is listed in Table 5-66.

DISCLOSURE CATEGORY EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Customer Connections	1,824,800	588,800	1,648,061	804,210
System Growth	995,510	106,923	299,965	615,804
Reliability, Safety & Environmental	2,092,193	1,360,863	2,205,596	895,079
Asset Replacement & Renewal – excluding Line Renewal	1,743,718	1,102,253	970,132	733,850
Asset Replacement & Renewal – Line Renewal (includes emergent)	5,404,070	5,625,406	5,762,445	5,688,861
Asset Relocation	50,648	50,648	50,648	50,648
TOTALS	**12,110,939**	**8,834,893**	**10,936,847**	**8,788,452**

TABLE 5-66: SUMMARY OF EXPENDITURE PREDICTIONS GROUPED BY DISCLOSURE CATEGORIES FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

5.8.2.1 Customer Connection Capital Expenditure Predictions

Scope of General, Subdivision and Industrial Connection Expenditure

This includes earthing, substations, points of connection, isolation/protection, transformers, switchgear and other items associated with general, subdivision and industrial new connections. Contingencies for general connections, transformers and earthing; subdivisions and unallocated; industrials have been reduced from the boom years of economic activity to a lower level. The estimates have been increased from 2015 onwards to reflect an increased level of activity based on the assumption that the effects of the 2009 recession will likely be over by this time.

Table 5-67 summaries the Customer Connection expenditure predictions for the years 2013/14 through to 2016/17 without inflation.

CUSTOMER CONNECTION EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**
General new connection contributions	318,270	318,270	371,315	371,315
Subdivision new connection contributions	111,395	111,395	137,917	137,917
Industrial new connection and unallocated contributions	159,135	159,135	238,703	238,703
Substation & Supply Points	515,000	-	787,856	56,275
33 kV Lines	721,000	-	112,270	-
TOTALS	**1,824,800**	**588,800**	**1,648,061**	**804,210**

TABLE 5-67: CUSTOMER CONNECTION EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

Scope of Specific Projects for 2013/14

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels. (It is not possible to provide any more detail on these because specific customer requirements are unknowns and short term.)
2. The substation and supply point and 33 kV line proposed projects are:
   a. Build a modular substation on Tirohanga Road to provide backup supply to the Mokai Energy Park; this work is in conjunction with a new 33 kV line. This work will satisfy the customers' requirement for a reliable supply; it is to be customer funded. A contract is yet to be negotiated.
   b. Build a 33 kV line to the modular substation outlined above.

Scope of Specific Projects for 2014/15

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels.
2. No customer connection substation and supply points or 33 kV Line projects are expected during this period.

Scope of Specific Projects for 2015/16

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels.
2. Substation and supply points and 33 kV line projects:
    a. Additional expenditure has been included for improving the reliability of the Taharoa lines in conjunction with expansion proposals at the site. This is base on the expectation that the Iron Sands will require an improved level of reliability. (An allowance of $112,270 has been included.)
    b. Additional expenditure has been included for upgrading the Taharoa substation in conjunction with an expanded and a more reliability critical Iron Sand operation. There are two drivers for this; the first being that there is an expectation that the Iron Sands will require an improved level of reliability. The second is that the existing equipment is aged and operating in an extreme environment. There are hazards associated with existing equipment and these need considering.

Scope of Specific Projects for 2016/17

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels.
2. Substation and supply points and 33 kV line projects:
    a. This expenditure is for follow-on work for Taharoa substation if the work in the previous year is finished and the customer wants further upgrade work completed.

5.8.2.2 System Growth Capital Expenditure Predictions

Table 5-68 lists the system growth capital expenditure predictions for the period 2013/14 through to 2016/17 without inflation.

SYSTEM GROWTH EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Sub transmission	483,918	-	103,000	281,381
Regulators	202,593	106,923	196,965	196,965
Cumulative Capacity	309,000	-	-	137,459
TOTAL	**995,510**	**106,923**	**299,965**	**615,805**

TABLE 5-68: SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

Scope of Specific Projects for 2013/14

1 Sub transmission
Voltage regulators are to be installed on the Kuratau supply at Manunui. This work is to align with Manunui rebuild. This is the lowest cost option given the low growth in the area and the income from customers connected. The justification for this work is unacceptable voltage levels if left as is when supply is in the reverse direction form Kuratau.

Ohakune point of supply has a cross bus that is Dog conductor, which is constrained in the winter season. For reliability, one feeder is to split off before the cross bus and allow capacity for a spare feeder. There is no known non-asset solution

An allowance has been included for installing fans on the Atiamuri 33/11 kV transformer to extend its capacity.

2 Regulators
The Wharepapa feeder supplied from Arohena zone substation has two legs that split out from the existing voltage regulator. Due to dairying load growth both these legs are now experiencing voltage problems. The plan includes two voltage regulators, one for each leg. This will also assist the network when back feeding from the Te Waireka zone substation in Otorohanga.

3 Cumulative Capacity: 11 kV
The creation of a new modular substation on Tirohanga road will require the upgrade of the 11 kV conductors from the point it reduces from Ferret to Squirrel to the site of the new substation; this is approximately 3 km of line. The conductor is to be Mink or equivalent AAAC.

Scope of Specific Projects for 2014/15

1 Regulators
The allowance is for an additional regulator on the Ohakune town boundary to support voltage into the town during major holiday weekends.

Scope of Specific Projects for 2015/16

1 Sub transmission
The allowance is for additional reactive power capacitor installation in Manunui, Taumarunui or Tuhua/Nihoniho to give additional stability and capacity in a back feed situation when the Ongarue Transpower substation is not available.

2 Regulators
Two voltage regulators are proposed. These will be dependant on system growth. The units are proposed for:

a. Whibley Road
The voltage regulator at this existing site is old and overloads when back feeding. The proposal is to replace it with an increased capacity regulator and one that can operate in the reverse direction.

b. Mokau
The Mokau feeder sees voltage drops in the holiday season and over the winter period. The proposal is to install a voltage regulator prior to an existing regulator to increase voltage that is presently marginally compliant.

Scope of Specific Projects for 2016/17

1 Sub transmission
Install an additional voltage regulator on the Whakamaru 33 kV line near Maraetai zone substation to boost the voltage, especially when back feeding from Atiamuri supply point.

2 Regulators
An allowance for an additional two voltage regulators is included for the Mokai and Rangitoto feeders. The Mokai regulator is necessary to accommodate lad growth from small lifestyle blocks and dairying. The Rangitoto regulator is to support load growth due to dairying development.

3 Cumulative capacity: 11 kV
There are two projects scheduled. These are:
a. Turoa / Ohakune
The Turoa / Ohakune feeders have a small section of cable at a tie point between them that is not rated for the current it may have to carry. The allowance is for the replacement of this cable with a larger size conductor.
b. Rangataua
This is the second stage of the feeder development work for Rangataua; stage one is to be done in 2013/13. Customers are experiencing voltage problems due to the long runs of low voltage overhead lines. The project involves extending the 11 kV network in Rangataua.

Non-asset solutions for all system growth projects include peak reduction and power factor improvement. Options for these are signalled by pricing.

5.8.2.3 Reliability, Safety and Environmental Capital Expenditure Predictions

Table 5-69 lists the reliability, hazard elimination/minimisation projects and environmental capital expenditure predictions for the period 2013/14 through to 2016/17 without inflation.

RELIABILITY, SAFETY, ENVIRONMENTAL EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
	2013/14	**2014/15**	**2015/16**	**2016/17**
Reliability	348,911	255,525	635,914	180,082
Hazard Elimination/Minimisation (Safety)	1,396,873	1,105,337	1,569,682	681,232
Environmental	346,409	-	-	33,765
Totals	**2,029,193**	**1,360,862**	**2,205,596**	**895,079**

TABLE 5-69: RELIABILITY, SAFETY AND ENVIRONMENTAL PROJECT EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

5.8.2.3.1 Reliability

There are no known non-asset solutions for automated switches. The justification for the projects is that customers expect a reliable supply and these sites will give customer minutes within the 2003 Reliability Report ranges. (0 to 15 cents per customer minute).

Scope of Specific Projects for 2013/14

1 Switches programmed for automation to improve network reliability include:
   a. ABS 434 on the Tirohanga Feeder
   b. ABS 454 on the Tihoi Feeder
   c. Links 5150 on the Waihaha Feeder
   d. ABS 5404 and ABS 5795 on the Western Feeder
   e. ABS 5914 on the Manunui Feeder
   f. ABS 1316 on the Te Mapara Feeder
   g. Recloser 730 on the Te Kuiti South Feeder.

2 Hakiaha feeder low voltage tie between transformers in CBD. To be done in conjunction with switchgear for 01A38 and 01A82.

Scope of Specific Projects for 2014/15

1 Switches programmed for automation to improve network reliability include:
   a. ABS 423 on the Pureora Feeder
   b. ABS 5984 on the Tokaanu / Kuratau 33 kV line
   c. ABS 5207 on the Rangipo / Hautu Feeder
   d. Links 6127 on the Northern Feeder
   e. ABS 5831 on the Hakiaha Feeder
   f. ABS 645 & ABS 308 on the Otorohanga Feeder.

2 Build a semi -mobile load control plant that can be relocated. Reuse the load control plant that is to be removed from National Park. This is the lowest cost option. It would be difficult to justify and construct full redundancy at each site. Work is proposed to be completed in conjunction with the National Park rebuild. A new plant is proposed to be purchased and containerised. The existing National Park plant would then be swapped out and set up as the modular plant.

Scope of Specific Projects for 2015/16

1 Switches programmed for automation to improve network reliability include:
   a. Sectionaliser 6353 on the Kuratau Feeder
   b. ABS 5838 on the Matapuna Feeder
   c. ABS 5912 on the Manunui Feeder
   d. ABS 5151 on the National Park Feeder
   e. ABS 288 on the Otorohanga Feeder.

2 To improve reliability and for added security, build a semi-mobile containerised 2.5 MVA substation. Non network solutions would be to hire in generator or mobile substation at times of network or substation failure, but this would be a more expensive option.

Scope of Specific Projects for 2016/17

Switches programmed for automation to improve network reliability include:
   a. Links 6355 on the Kuratau Feeder
   b. ABS 5680 On the Turoa Feeder
   c. ABS 6118 on the Tangiwai Feeder
   d. ABS 387 & ABS 328 on the McDonalds Feeder.

5.8.2.3.2 Hazard Elimination/Minimisation (Safety)

There are no non-asset alternatives to the network having to be hazard controlled for the public and staff.

Scope of Specific Projects for 2013/14

1 Pillar box hazard elimination - 40 pillars programmed for this year.

2 Two pole transformer structures programmed for safety improvements include:
   a. 07Q14 - Waihaha Feeder
   b. 20M08 – Turoa Feeder
   c. 15L05 – National Park Feeder
   d. 11S04 – Rangipo / Hautu.

3 Ground mounted transformers programmed for safety improvements include:
   a. T701 - Mangakino Feeder
   b. 10S42 & 10S41 - Turangi Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 01A38 & 01A82 – Hakiaha Feeder
   b. 20L15 – Ohakune Town Feeder
   c. 16N17 – Chateau Feeder.

5 Manunui zone substation layout poses a hazard to workers and the public; a rebuild of the site is the lowest cost option.

6 The refurbishment of zone transformer at the Manunui Zone substation. This is the most cost effective solution for the short term.

7 Taumarunui CBD low voltage ties are essential to maintain supply to customer. Feeder development work is included in the Plan to extend the low voltage reticulation between transformers 01A38 and 01A82 and create a normally open switch between the two systems.

8 Rationalise the number of outgoing feeder circuit breakers at the National Park POS and improve site hazard control.

Scope of Specific Projects for 2014/15

1 Pillar box hazard elimination - 37 pillars programmed for this year.

2 Two pole transformer structures programmed for safety improvements include:
   a. 09T04 - Motuoapa Feeder
   b. 08R09 - Kuratau Feeder
   c. 05G03 – Tuhua Feeder
   d. 01K02 - Ongarue Feeder
   e. 08K14 & 07K11 - Manunui Feeder
   f. T559 – Te Kuiti South Feeder
   g. 13I10 & T4132 – Raurimu Feeder
   h. T2153 - Mokau Feeder.

3 Ground mounted transformers programmed for safety improvements include:
   a. T700 - Mangakino Feeder
   b. 10S44 - Turangi Feeder
   c. 14L12 – National Park Feeder
   d. T663 - Oparure Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 09U11 – Oruatua Feeder
   b. 08R20 - Kuratau Feeder
   c. 08I55 – Western Feeder
   d. 17N04 – Turoa Feeder
   e. 16N21 – Chateau Feeder.

5 Tawhai zone substation fence has gaps in it that have been temporarily repaired. The site is located on the edge of a State Highway and main tourist route. Substation security is vital to maintaining a safe environment for the public.

6 Feeder development work is planned for the Oruatua feeder, part of which crosses a trout fishing stream. This line creates a hazard to those fishing. The plan includes installing cable and attaching it to the bridge that crosses the stream. This work is to be done in conjunction with work on transformer 09U11.

Scope of Specific Projects for 2015/16

1 Pillar box hazard elimination - 30 pillars programmed for this year.

2 Two pole transformer structures programmed for safety improvements include:
   a. 09K50 - Southern Feeder
   b. 01A46 - Northern Feeder
   c. 01B11 – Hakiaha Feeder
   d. 20L06 - Tangiwai Feeder
   e. T1777 – Te Mapara Feeder
   f. 09R27 – Kuratau Feeder
   g. T1865, T2520 & T1453 - Mahoenui Feeder.

3 Ground mounted transformers programmed for safety improvements include:
   a. 10S26 - Turangi Feeder
   b. T406 - Waitomo Feeder
   c. T381 – Hangatiki East Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 09R14 & 09R16 – Kuratau Feeder
   b. 20L43 - Tangiwai Feeder
   c. 20L59 & 20L68 – Ohakune Town Feeder.

5 Waitete zone substation fence needs replacement to improve security of the site.

6 Turangi Zone Substation - renew 11 kV circuit breakers.

7 Reticulation renewal work is planned for the Whakamaru old hydro village. The reticulation is old and hazardous. The houses are directly connected to the low voltage reticulation with no isolation equipment at the point of supply. The proposal is to address this issue and also install a 300 kVA transformer at site T2523 and remove units T2524 and T2521. Through-joint at T2523 and 2525 and replace LV cable around village with 4c Cable, new 16mm^2 N/S street light cable and TUDs pillar boxes. May need to include replacement of service-mains to boxes currently installed on the house walls.

Scope of Specific Projects for 2016/17

1 Pillar box hazard elimination - 10 pillars programmed for this year. The number has been reduced due to the work done in previous years. (The hazardous legacy sites have now been addressed.)

2 Two pole transformer structures programmed for safety improvements include:
   a. T1081 - Mangakino Feeder
   b. T2506- Benneydale Feeder
   c. 02K08 - Ongarue Feeder
   d. 09K25 – Southern Feeder
   e. 08I21- Western Feeder
   f. 08L17 – Manunui Feeder
   g. T1829 – Te Mapara Feeder
   h. 20M07- Turoa Feeder

3 Ground mounted transformers programmed for safety improvements include:
   a. 10S29 - Turangi Feeder
   b. 07D24 - Ohura Feeder
   c. T464 – Rangitoto Feeder
   d. T457 - Oparure Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 10S03 – Rangipo / Hautu Feeder
   b. 20L45 - Tangiwai Feeder
   c. 16N09 – Chateau Feeder.

5.8.2.3.3 Environmental

There are no known non-asset solutions. The justification is environmental compliance and TLC being a responsible corporate citizen. Oil spills into nearby rivers would also attract fines and clean-up costs.

Scope of Specific Projects for 2013/14

1 Manunui zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.

2 National Park Zone Substation is located next to a DOC reserve and near a main tourist route and State Highway. The substation is in an earthquake prone area and likely to experience liquefaction. The fence is in a poor state and the transformer is on a concrete plinth. The most cost effective solution is to rebuild the site with a modular substation in conjunction with other work planned for the site.

Scope of Specific Projects for 2016/17

1 Borough zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.
2 Hangatiki zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.

5.8.2.4 Asset Replacement & Renewal excluding Line Renewal Capital Expenditure Predictions

Table 5-70 lists the asset replacement and renewal expenditure for the years 2013/14 to 2016/17.

ASSETS RENEWAL AND REPLACEMENT - EXCLUDING LINE RENEWALs CAPITAL EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Asset	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Ongarue POS Circuit Breakers	675,305	0	0	0
Manunui Zone Substation Transformer refurbish	90,041	0	0	0
Equipment Renewals	668,380	792,261	660,140	667,350
Relays	309,993	309,993	309,993	66,501
Totals	**1,743,719**	**1,102,254**	**970,133**	**733,851**

TABLE 5-70: ASSET REPLACEMENT & RENEWAL EXPENDITURE (EXCLUDING LINE RENEWALS) FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

5.8.2.4.1 Ongarue POS Circuit Breaker

It is more cost effective for TLC to have its own 33kV bus system, than pay the high annual connection charges associated with circuit breakers to Transpower. Typically, Transpower's annual charges are 1.5 times the capital cost of a circuit breaker. There is a potential to remove 3 Transpower owned circuit breakers and reduce site hazards and improve operational ease. Reliability and security will also benefit.

5.8.2.4.2 Manunui Zone Substation Transformer

Oil tests indicate transformer life can be extended with refurbishment. This is the most cost effective solution and improves network security.

5.8.2.4.3 Equipment Renewals

General non-specific individual equipment renewal contingencies for the next four years are summarised in Table 5-71.

EQUIPMENT RENEWAL CAPITAL EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Category	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Radio Specific	159,650	170,980	151,410	158,620
Radio Contingency	11,255	11,255	11,255	11,255
SCADA Specific	41,644	41,644	41,644	41,644
SCADA Contingency	16,883	16,883	16,883	16,883
Tap-offs with new connections	33,765	33,765	33,765	33,765
Load Control	0	112,551	0	0
Transformer Renewals	337,653	337,653	337,653	337,653
Protection	11,255	11,255	11,255	11,255
Distribution Equipment	56,275	56,275	56,275	56,275
TOTAL	**668,380**	**792,261**	**660,140**	**667,350**

TABLE 5-71: EQUIPMENT RENEWAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

5.8.2.4.3.1 Radio Specific

On-going upgrade of the radio system to comply with new spectrum requirements. This will involve upgrading TLC communications to a digital network.

5.8.2.4.3.2 Radio Contingency

This is a contingency amount per annum for replacing radio equipment on failure. From time to time water gets into aerials and lightning destroys repeaters.

5.8.2.4.3.3 SCADA Specific

Annual allowance based on recommendations from SCADA experts to keep equipment up to date.

5.8.2.4.3.4 SCADA Contingency

This is a contingency amount per annum for replacing failed SCADA equipment.

5.8.2.4.3.5 Tap-offs with New Connections

This is a contingency amount per annum to cover brought forward renewals associated with replacing poles when new customer connections are taking place.

5.8.2.4.3.6 Load Control

This is an amount for renewals and upgrades to the load control plants.

5.8.2.4.3.7 Distribution Transformer Renewals

This is a contingency amount per annum for renewal of transformers that are uneconomic to repair. (Generally repair cost is greater than regulatory value). Typically units are renewed when repair cost is greater than regulatory value: see earlier sections for criteria details.

5.8.2.4.3.8 Protection

This is a contingency amount per annum for replacing relays and voltage control equipment on failure.

5.8.2.4.3.9 Distribution Equipment Contingency

This is a contingency amount per annum for failed equipment. (Typically circuit breakers and regulators.)

5.8.2.4.3.10 On-going Radio Equipment Renewals

Annual allowance based on recommendations from communication specialists to keep equipment up to date.

5.8.2.4.4 Load Control Relays

Expenditure is for the continuation with the upgrade of relays to the advanced meter type within TLC's network as described in the preceding section.

5.8.2.5 Asset Replacement & Renewal – Line Renewal Capital Expenditure Predictions

The Line Renewal projects planned for 2013/14 to 2016/17 are detailed in Section 6 of the AMP. A summary of the proposed expenditure for the next four years is shown in Table 5-72.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Projects	**2013/14**	**2014/15**	**2015/16**	**2016/17**
33 kV Line Renewal (includes emergent)	978,016	573,146	464,985	655,058
11 kV Line Renewals (includes emergent)	4,306,703	4,850,689	4,607,875	4,498,048
LV Line Renewals (includes emergent)	119,351	201,571	689,585	535,755
TOTAL	**5,404,070**	**5,625,406**	**5,762,445**	**5,688,861**

TABLE 5-72: ASSET REPLACEMENT AND RENEWAL – LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

5.8.2.6 Asset Relocation Capital Expenditure Predictions

The scope of works for asset relocations is associated with road re-alignments and relocations of lines when slips occur. TLC cannot forward plan for these.

An allowance of $50,648 p.a. has been included for the planning period.

There are usually no non-asset solutions that can be used for asset relocations. Projects are justified as part of compliance.

5.8.3 Summary of Capital Projects and Expenditure Predictions 2012/13 to 2016/17

Stakeholders have requested more detailed lists of proposed works. In the 2011/12 plan section 11 was added; however at this time the source data was coming from a complex array of spread-sheets and thus putting together a simplified list of work for the next 10 years was difficult. Over the last 12 months the source data has been moved into the Basix database and as a consequence of this it has been possible to list the information in more flexible formats. The following tables summarise capital expenditure projects and cost predictions by Point of Supply (or GXP) and for the years 2012/13 to 2016/17.

Table 5-73 lists the work that relates to non-specific Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
2012/13	Customer Driven Projects	Various	General Connections - Transformers	159k
2012/13	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	32k
2012/13	Customer Driven Projects	Various	Industrials - Transformers	106k
2012/13	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2012/13	Customer Driven Projects	Various	Subdivisions - Management	11k
2012/13	Customer Driven Projects	Various	Subdivisions - Transformers	80k
2012/13	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2012/13	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2012/13	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2012/13	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	101k
2012/13	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2012/13	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2012/13	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2012/13	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2012/13	Network Equipment Renewal	Whole Network	Protection	11k
2012/13	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2012/13	Network Equipment Renewal	Whole Network	RADIO Specific	177k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Network Equipment Renewal	Whole Network	Relay Changes - Special	107k
2012/13	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2012/13	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2012/13	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2012/13	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2013/14	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
2013/14	Customer Driven Projects	Various	General Connections - Transformers	159k
2013/14	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2013/14	Customer Driven Projects	Various	Industrials - Transformers	106k
2013/14	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2013/14	Customer Driven Projects	Various	Subdivisions - Management	11k
2013/14	Customer Driven Projects	Various	Subdivisions - Transformers	80k
2013/14	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2013/14	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2013/14	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2013/14	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	86k
2013/14	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2013/14	Network Equipment Renewal	Whole Network	Protection	11k
2013/14	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2013/14	Network Equipment Renewal	Whole Network	RADIO Specific	160k
2013/14	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2013/14	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2013/14	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2013/14	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2014/15	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
2014/15	Customer Driven Projects	Various	General Connections - Transformers	159k
2014/15	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2014/15	Customer Driven Projects	Various	Industrials - Transformers	106k
2014/15	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2014/15	Customer Driven Projects	Various	Subdivisions - Management	11k
2014/15	Customer Driven Projects	Various	Subdivisions - Transformers	80k
2014/15	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2014/15	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2014/15	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2014/15	Network Equipment Renewal	Whole Network	Have a semi mobile Load Control plant that can be relocated. Reuse the load control plant that is removed from National Park.	68k
2014/15	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	80k
2014/15	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2014/15	Network Equipment Renewal	Whole Network	Load Control	113k
2014/15	Network Equipment Renewal	Whole Network	Protection	11k
2014/15	Network Equipment Renewal	Whole Network	Radio Contingency	11k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Network Equipment Renewal	Whole Network	RADIO Specific	171k
2014/15	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
2014/15	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2014/15	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2014/15	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2014/15	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2015/16	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
2015/16	Customer Driven Projects	Various	General Connections - Transformers	186k
2015/16	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2015/16	Customer Driven Projects	Various	Industrials - Transformers	186k
2015/16	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2015/16	Customer Driven Projects	Various	Subdivisions - Management	11k
2015/16	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2015/16	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2015/16	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2015/16	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2015/16	Network Equipment Renewal	Whole Network	Semi mobile containerised 2.5 MVA substation.	450k
2015/16	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	64k
2015/16	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2015/16	Network Equipment Renewal	Whole Network	Protection	11k
2015/16	Network Equipment Renewal	Whole Network	Radio Contingency	11k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Network Equipment Renewal	Whole Network	RADIO Specific	151k
2015/16	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
2015/16	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2015/16	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2015/16	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2015/16	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2016/17	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
2016/17	Customer Driven Projects	Various	General Connections - Transformers	186k
2016/17	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2016/17	Customer Driven Projects	Various	Industrials - Transformers	186k
2016/17	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2016/17	Customer Driven Projects	Various	Subdivisions - Management	11k
2016/17	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2016/17	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2016/17	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2016/17	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2016/17	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	21k
2016/17	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2016/17	Network Equipment Renewal	Whole Network	Protection	11k
2016/17	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2016/17	Network Equipment Renewal	Whole Network	RADIO Specific	159k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Network Equipment Renewal	Whole Network	Relay Changes - Special	67k
2016/17	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2016/17	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2016/17	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2016/17	Network Equipment Renewal	Whole Network	Transformer Renewals	338k

TABLE 5-73: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR NON SPECIFIC POS (WITHOUT INFLATION)

Table 5-74 lists the work that relates to Hangatiki Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Line Renewal	Mokau	128-06 11kV Line Renewal	376k
2012/13	Line Renewal	Mokauiti	115-04 11kV Line Renewal	138k
2012/13	Line Renewal	Benneydale	103-05 11kV Line Renewal	257k
2012/13	Line Renewal	Benneydale	103-06 11kV Line Renewal	139k
2012/13	Line Renewal	Mokauiti	115-03 11kV Line Renewal	275k
2012/13	Line Renewal	Waitomo	108-03 11kV Line Renewal	104k
2012/13	Line Renewal	Aria	114-03 11kV Line Renewal	117k
2012/13	Line Renewal	McDonalds	110-05 11kV Line Renewal	248k
2012/13	Line Renewal	Maihiihi	111-08 11kV Line Renewal	88k
2012/13	Line Renewal	Hangatiki East	102-03 11kV Line Renewal	63k
2012/13	Line Renewal	Waitomo	108-03 LV Line Renewal	64k
2012/13	Line Renewal	Mokau	128-06 LV Line Renewal	42k
2012/13	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Replace 11 kV Circuit breaker with modern equipment and increase the functionality of the breaker. Risk to reliability and security and protection not operating	68k
2012/13	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Modify and install oil bunding, oil separation and earthquake restraints.	28k
2012/13	Substation and 33 kV Development	Te Waireka Zone Substation	ZSub203 Modify and install bunding, oil bunding, oil separation and earthquake restraints.	28k
2013/14	Line Renewal	Mahoenui	113-03 11kV Line Renewal	202k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Line Renewal	Te Mapara	117-04 11kV Line Renewal	299k
2013/14	Line Renewal	Te Kuiti Town	105-01 11kV Line Renewal	138k
2013/14	Line Renewal	Rangitoto	106-05 11kV Line Renewal	305k
2013/14	Line Renewal	Gravel Scoop	109-04 11kV Line Renewal	318k
2013/14	Line Renewal	Piopio	116-05 11kV Line Renewal	133k
2013/14	Line Renewal	Oparure	107-05 11kV Line Renewal	221k
2013/14	Line Renewal	Oparure	107-06 11kV Line Renewal	221k
2013/14	Line Renewal	Gravel Scoop	109-05 11kV Line Renewal	227k
2013/14	Line Renewal	Mokau	128-08 LV Line Renewal	7k
2013/14	Line Renewal	Mahoenui	113-03 LV Line Renewal	7k
2013/14	Switches	Te Kuiti South	730 Add remote communication	23k
2013/14	Switches	Te Mapara	1316 Automate Switch	23k
2014/15	Line Renewal	Caves	101-09 11kV Line Renewal	30k
2014/15	Line Renewal	Aria	114-05 11kV Line Renewal	261k
2014/15	Line Renewal	Aria	114-04 11kV Line Renewal	161k
2014/15	Line Renewal	Benneydale	103-08 11kV Line Renewal	68k
2014/15	Line Renewal	Gravel Scoop	109-14 11kV Line Renewal	233k
2014/15	Line Renewal	Caves	101-10 11kV Line Renewal	86k
2014/15	Line Renewal	Mokauiti	115-05 11kV Line Renewal	204k
2014/15	Line Renewal	Mokau	128-09 11kV Line Renewal	99k
2014/15	Line Renewal	Mokau	128-08 11kV Line Renewal	484k
2014/15	Line Renewal	Otorohanga	112-07 11kV Line Renewal	98k
2014/15	Line Renewal	Mahoenui	113-05 11kV Line Renewal	244k
2014/15	Line Renewal	Mokauiti	115-06 11kV Line Renewal	155k
2014/15	Line Renewal	Gravel Scoop	109-06 11kV Line Renewal	279k
2014/15	Line Renewal	Benneydale	103-07 LV Line Renewal	64k
2014/15	Switches	Otorohanga	645 Switch Automation	11k
2014/15	Switches	Otorohanga	308 Switch Automation	11k
2014/15	Transformers - 2 Pole Structures	Te Kuiti South	T559 Rebuild structure, replace poles, use standard single pole if possible.	56k
2014/15	Transformers - 2 Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	23k
2014/15	Transformers - Ground Mounted	Oparure	T663 Replace with refurbished I tank transformer.	45k
2015/16	Line Renewal	Benneydale	103-08 11kV Line Renewal	68k
2015/16	Line Renewal	Mahoenui	113-06 11kV Line Renewal	222k
2015/16	Line Renewal	Coast	125-06 11kV Line Renewal	179k
2015/16	Line Renewal	Rural	126-03 11kV Line Renewal	3k
2015/16	Line Renewal	Maihiihi	111-10 11kV Line Renewal	320k
2015/16	Line Renewal	Mahoenui	113-07 11kV Line Renewal	107k
2015/16	Line Renewal	Coast	125-05 11kV Line Renewal	307k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Line Renewal	Caves	101-11 11kV Line Renewal	51k
2015/16	Line Renewal	Te Mapara	117-06 11kV Line Renewal	221k
2015/16	Line Renewal	Coast	125-05 LV Line Renewal	32k
2015/16	Regulators	Mokau Feeder	FED128 Near Bolts place on top of hill	101k
2015/16	Regulators	Maihiihi	REG06 Replace Whibley Road regulator. This is an old type of regulator and overload when back feeding.	96k
2015/16	Substation and 33 kV Development	Taharoa B Feeder	FED302 Renew and remove hazardous equipment. Customer has not made a decision: Coincides with confirmed upgrading of site. Cost to bring reliability to expectations of large 24/7 plant.	112k
2015/16	Substation and 33 kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	788k
2015/16	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Replace fence	68k
2015/16	Switches	Otorohanga	288 Switch Automation	28k
2015/16	Transformers - 2 Pole Structures	Mahoenui	T1865 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
2015/16	Transformers - 2 Pole Structures	Te Mapara	T1777 Rebuild structure with transformer higher up pole. Use standard single pole design if practical.	45k
2015/16	Transformers - 2 Pole Structures	Mahoenui	T1453 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2015/16	Transformers - 2 Pole Structures	Mahoenui	T2520 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2015/16	Transformers - Ground Mounted	Waitomo	T406 Rebuild to regulations and current TLC standards.	45k
2015/16	Transformers - Ground Mounted	Hangatiki East	T381 Replace with I tank or front access transformer. Use a refurbished transformer if available.	45k
2016/17	Line Renewal	McDonalds	110-04 11kV Line Renewal	39k
2016/17	Line Renewal	Benneydale	103-10 11kV Line Renewal	267k
2016/17	Line Renewal	McDonalds	110-03 11kV Line Renewal	84k
2016/17	Line Renewal	Gravel Scoop	109-07 11kV Line Renewal	313k
2016/17	Line Renewal	Mokau	128-07 11kV Line Renewal	75k
2016/17	Line Renewal	Caves	101-12 11kV Line Renewal	253k
2016/17	Line Renewal	Maihiihi	111-11 11kV Line Renewal	146k
2016/17	Line Renewal	Aria	114-06 11kV Line Renewal	142k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Line Renewal	Otorohanga	112-05 11kV Line Renewal	3k
2016/17	Line Renewal	Mahoenui	113-08 11kV Line Renewal	217k
2016/17	Line Renewal	Maihiihi	109-08 11kV Line Renewal	79k
2016/17	Line Renewal	Caves	101-13 11kV Line Renewal	126k
2016/17	Line Renewal	Benneydale	103-11 11kV Line Renewal	267k
2016/17	Line Renewal	Otorohanga	112-06 11kV Line Renewal	103k
2016/17	Line Renewal	Te Waireka Rd 33	303-01 33kV Line Renewal	181k
2016/17	Regulators	Rangitoto Feeder	FED106 Regulator towards Otewa Rd, also to pick up Otewa when working on Gravel Scoop and Waipa Gorge	96k
2016/17	Substation and 33 kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	56k
2016/17	Substation and 33 kV Development	Hangatiki Zone Substation	ZSub204 Install oil separation.	17k
2016/17	Switches	McDonalds	387 Automate Switch. Replace pole and install ENTEC.	34k
2016/17	Switches	McDonalds	328 Automate Switch. Install a Motor Actuator onto existing ABS.	23k
2016/17	Transformers - 2 Pole Structures	Te Mapara	T1829 Check ground clearance - raise transformer on pole.	8k
2016/17	Transformers - 2 Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure.	28k
2016/17	Transformers - Ground Mounted	Oparure	T457 Install a front access transformer 300 kVA with I Blade RTE switch.	45k
2016/17	Transformers - Ground Mounted	Rangitoto	T464 Replace with a refurbished I Tank. Check loading and size transformer appropriately.	45k

TABLE 5-74: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR HANGATIKI POS (WITHOUT INFLATION)

Table 5-75 lists the work that relates to National Park Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Line Renewal	Raurimu	410-01 11kV Line Renewal	237k
2012/13	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Transformer Refurbishment	90k
2012/13	Switches	Raurimu Feeder	FED410 Install Recloser for Retaruke tap-off at Raurimu Hill.	56k
2012/13	Switchgear	Chateau	T4066 Upgrade Transformer Install Xiria.	45k
2013/14	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
2013/14	Substation and 33 kV Development	National Park Point of Supply	ZSub516 Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers and containerise the switchgear for the 11 kV Feeders. This work aligns with the installation of a new modular substation with the switchgear in a container. (See Zone Substations)	675k
2013/14	Substation and 33 kV Development	National Park Zone Substation	ZSub501 Rebuild Site. Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	318k
2013/14	Switchgear	Chateau	16N17 Add switchgear to this site.	45k
2013/14	Transformers - 2 Pole Structures	National Park	15L05 Transformer is close to motel balcony. Ground mount transformer, check loadings for transformer size.	45k
2014/15	Line Renewal	National Park	411-02 11kV Line Renewal	401k
2014/15	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
2014/15	Line Renewal	National Park 33	601-01 33kV Line Renewal	31k
2014/15	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Renew fence	56k
2014/15	Switchgear	Chateau	16N21 Add 11 kV switchgear to transformer.	45k
2014/15	Transformers - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k
2014/15	Transformers - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer . ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	45k
2015/16	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
2015/16	Line Renewal	No Feeder	610-01 33kV Line Renewal	51k
2015/16	Switches	National Park	5151 Automate switch in Substation	45k
2016/17	Line Renewal	Raurimu	410-03 11kV Line Renewal	307k
2016/17	Line Renewal	National Park / Kuratau 33	609-04 33kV Line Renewal	268k
2016/17	Switchgear	Chateau	16N09 Install switchgear	45k

TABLE 5-75: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR NATIONAL PARK POS (WITHOUT INFLATION)

Table 5-76 lists the work that relates to Ohakune Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Feeder Development	Turoa	415-04 Redesign over LV and HV configuration for Rangataua. Check loading of all transformers including 20M09. Work in association with planned change of two pole structures 20M07 in 12/13 year and 20M08 in 13/14. Assess LV wire size and extending LV. Work to alleviate low voltage problems and possible development of empty sections. Do part in 12/13 and part in year 16/17.	84k
2012/13	Line Renewal	Turoa	415-03 11kV Line Renewal	71k
2012/13	Substation and 33 kV Development	Ohakune Point of Supply	ZSub517 Take supply for part of area from neighbouring Transpowers Tangiwai Grid Exit.	464k
2012/13	Switches	Tangiwai	5673 Automate switch	23k
2012/13	Switches	Turoa	6356 Switch Automation. Install a Schneider Motor Drive unit & Aerial	23k
2012/13	Switchgear	Ohakune Town	20L50 Upgrade transformer to include RTE	45k
2012/13	Switchgear	Ohakune Town	6321 Install RMU to remove 3 cables from pole in Ayr Street and two cables fused off this switch. This will supply 20L61, 20L59 and 20L60.	45k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Substation and 33 kV Development	Ohakune Point of Supply	ZSub517 The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. Break into the circuit before the cross bus. Split one feeder off. Have capacity for a spare feeder. Transpower planning includes a new 20 MVA transformer planned for 13/14 years.	169k
2013/14	Switchgear	Ohakune Town	20L15 Upgrade transformer to transformer with RTE.	45k
2013/14	Transformers - 2 Pole Structures	Turoa	20M08 Ground mount transformer, check loadings.	56k
2014/15	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	151k
2014/15	Regulators	Ohakune Town Feeder	FED414 Regulator at town boundary	107k
2014/15	Switchgear	Turoa	17N04 Need a visual break & earths. Switchgear needed	45k
2015/16	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	151k
2015/16	Line Renewal	Turoa	415-01 11kV Line Renewal	280k
2015/16	Line Renewal	Ohakune Town	414-01 LV Line Renewal	127k
2015/16	Line Renewal	Turoa	415-01 LV Line Renewal	106k
2015/16	Switchgear	Ohakune Town	20L68 Install additional switchgear	90k
2015/16	Switchgear	Tangiwai	20L43 Install RTE	45k
2015/16	Switchgear	Ohakune Town	20L59 Install transformer with RTE switch.	45k
2015/16	Transformers - 2 Pole Structures	Tangiwai	20L06 Replace structure with ground mounted transformer.	62k
2016/17	Feeder Development	Turoa	415-01 Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.	53k
2016/17	Feeder Development	Turoa	415-04 Redesign over LV and HV configuration for Rangataua. Check loading of all transformers including 20M09. Work in association with planned change of two pole structures 20M07 in 12/13 year and 20M08 in 13/14. Assess LV wire size and extending LV. Work to alleviate low voltage problems and possible development of empty sections. Do part in 12/13 and part in year 16/17.	84k
2016/17	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	213k
2016/17	Line Renewal	Turoa	415-01 11kV Line Renewal	280k
2016/17	Line Renewal	Ohakune Town	414-01 LV Line Renewal	127k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Line Renewal	Turoa	415-01 LV Line Renewal	133k
2016/17	Switches	Tangiwai	6118 Automate Switch	45k
2016/17	Switches	Turoa	5680 Automate Switch	45k
2016/17	Switchgear	Tangiwai	20L45 Install a transformer with RTE.	45k
2016/17	Transformers - 2 Pole Structures	Turoa	20M07 Ground mount transformer. Check loadings.	56k

TABLE 5-76: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR OHAKUNE POS (WITHOUT INFLATION)

Table 5-77 lists the work that relates to Ongarue Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Line Renewal	Tuhua	422-02 11kV Line Renewal	130k
2012/13	Line Renewal	Western	403-05 11kV Line Renewal	192k
2012/13	Line Renewal	Ohura	413-05 11kV Line Renewal	230k
2012/13	Line Renewal	Ongarue	421-01 11kV Line Renewal	214k
2012/13	Transformers - 2 Pole Structures	Ongarue	T4128 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Look at new options as 04I01 may be overloaded.	30k
2012/13	Transformers - 2 Pole Structures	Northern	01A50 Rebuild structure. 11 kV only 4m above ground. Ground mount transformer, if possible use a second hand 100 kVA.	48k
2012/13	Transformers - 2 Pole Structures	Northern	06H11 Raise equipment on structure, recloser at only 3.75m above the ground.	48k
2012/13	Transformers - 2 Pole Structures	Ongarue	04I01 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Check loading on 04I01 as load flow program indicates transformer could be overloaded.	30k
2013/14	Line Renewal	Ongarue	421-02 11kV Line Renewal	202k
2013/14	Line Renewal	Ohura	413-08 11kV Line Renewal	270k
2013/14	Line Renewal	Western	403-06 11kV Line Renewal	272k
2013/14	Line Renewal	Northern	402-05 11kV Line Renewal	336k
2013/14	Line Renewal	Ongarue / Taumarunui 33	604-01 33kV Line Renewal	500k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Line Renewal	Taumarunui / Kuratau 33	608-03 33kV Line Renewal	240k
2013/14	Line Renewal	Tuhua 33	602-01 33kV Line Renewal	32k
2013/14	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Regulators installed on Kuratau supply at Manunui To be done with Manunui rebuild	281k
2013/14	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Rebuild site. Replace incoming 33 kV Breaker.	169k
2013/14	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Refurbish transformer.	90k
2013/14	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Install oil separation.	28k
2013/14	Substation and 33 kV Development	Ongarue Point of Supply	ZSub514 Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho; remove Nihoniho breaker. Needs 4 line reclosers and one or two automated 33kV switches. Allows splitting of feeders and isolation of Transpower supply. Some 33kV cabling will be necessary. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	675k
2013/14	Switches	Hakiaha Feeder	FED401 Low voltage tie between transformers in CBD. Do in conjunction with switchgear for 01A38 and 01A82	113k
2013/14	Switches	Western	5404 Automate Switch	28k
2013/14	Switches	Manunui	5914 Automate Switch	34k
2013/14	Switches	Western	5795 Automate Switch	28k
2013/14	Switchgear	Hakiaha Feeder	FED401 Add 11 kV switchgear for 01A38 and 01A82	56k
2014/15	Line Renewal	Manunui	407-01 11kV Line Renewal	126k
2014/15	Line Renewal	Western	403-07 11kV Line Renewal	167k
2014/15	Line Renewal	Southern	409-07 11kV Line Renewal	167k
2014/15	Line Renewal	Ohura	413-03 11kV Line Renewal	163k
2014/15	Line Renewal	Taumarunui / Kuratau 33	608-02 33kV Line Renewal	336k
2014/15	Line Renewal	Manunui	407-01 LV Line Renewal	32k
2014/15	Switches	Northern	6127 Switch Automation	28k
2014/15	Switches	Hakiaha	5831 Switch Automation	34k
2014/15	Switchgear	Western	08I55 Install a RMU	45k
2014/15	Transformers - 2 Pole Structures	Manunui	08K14 Replace pole mounted transformer with refurbished ground mounted transformer.	49k
2014/15	Transformers - 2 Pole Structures	Tuhua	05G03 Lift equipment over regulation height and maintain clearances.	23k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - 2 Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	49k
2014/15	Transformers - 2 Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA transformer.	45k
2015/16	Line Renewal	Nihoniho	412-02 11kV Line Renewal	196k
2015/16	Line Renewal	Ohura	413-09 11kV Line Renewal	127k
2015/16	Line Renewal	Western	403-07 11kV Line Renewal	167k
2015/16	Line Renewal	Western	403-03 11kV Line Renewal	141k
2015/16	Line Renewal	Southern	409-08 11kV Line Renewal	229k
2015/16	Line Renewal	Ohura	413-04 11kV Line Renewal	286k
2015/16	Line Renewal	Ongarue	421-03 11kV Line Renewal	206k
2015/16	Line Renewal	Taumarunui / Kuratau 33	608-01 33kV Line Renewal	208k
2015/16	Line Renewal	Ongarue	421-03 LV Line Renewal	27k
2015/16	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Install reactive power capacitors.	103k
2015/16	Switches	Manunui	5912 Switch Automation	34k
2015/16	Switches	Matapuna	5838 Switch Automation	45k
2015/16	Transformers - 2 Pole Structures	Hakiaha	01B11 Rebuild structure with safer LV wiring. Raise the height of the transformer.	45k
2015/16	Transformers - 2 Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer.	45k
2015/16	Transformers - 2 Pole Structures	Southern	09K50 Check loading on transformer. Either 100 kVA standard single pole or 200 kVA refurbished and mount.	42k
2016/17	Line Renewal	Ongarue	421-04 11kV Line Renewal	372k
2016/17	Line Renewal	Southern	409-09 11kV Line Renewal	179k
2016/17	Line Renewal	Western	403-04 11kV Line Renewal	97k
2016/17	Line Renewal	Ongarue	421-03 LV Line Renewal	11k
2016/17	Substation and 33 kV Development	Borough Zone Substation	ZSub508 Install oil separation.	17k
2016/17	Transformers - 2 Pole Structures	Western	08I21 Raise equipment on structure to above regulation height for 11 kV from ground level. Maintain clearances.	56k
2016/17	Transformers - 2 Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	56k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Transformers - 2 Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level.	45k
2016/17	Transformers - 2 Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure.	42k
2016/17	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	45k

TABLE 5-77: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR ONGARUE POS (WITHOUT INFLATION)

Table 5-78 lists the work that relates to Tokaanu Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Line Renewal	Kuratau	406-01 11kV Line Renewal	18k
2012/13	Line Renewal	Waihaha	426-04 11kV Line Renewal	241k
2012/13	Line Renewal	Turangi	423-01 11kV Line Renewal	166k
2012/13	Line Renewal	Tokaanu / Kuratau 33	607-01 33kV Line Renewal	245k
2012/13	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 Rebuild fence	68k
2012/13	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 Add additional 33 kV switchgear. Leave existing reclosers. Upgrade protection schemes to ensure primary and backup protection is reliable. New 33 kV in year 12/13. Underground and remove double cct to be done at same time as far as 5673 tap-off. (See 11kV line renewals)	206k
2012/13	Substation and 33 kV Development	Tokaanu Point of Supply	ZSub515 Install switchgear capable of breaking a capacitive circuit. Sectos Switch in stock can be used for this project.	68k
2012/13	Switches	Turangi	5208 Install a 4 way Xiria at tap-off 5208 to supply Turangi and have a parallel with Rangipo Hautu	56k
2012/13	Switches	Turangi	6191 Automate 6191 tie to Hirangi Feeder from Turangi. This is an existing Magnefix therefore the switch will need to be changed.	56k
2012/13	Transformers - 2 Pole Structures	Oruatua	09U10 Replace with ground mounted transformer. Adjacent high wooden fence makes any structure a hazard.	68k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Transformers - 2 Pole Structures	Oruatua	09U07 Replace with a ground mounted transformer. Pole requires replacing and LV through trees. Earth mat looks to be damaged.	68k
2012/13	Transformers - Ground Mounted	Turangi	10S46 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
2012/13	Transformers - Ground Mounted	Turangi	10S31 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
2013/14	Switches	Waihaha	5150 Switch Automation	45k
2013/14	Transformers - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer. Downsize transformer as required. Rebuild with standard single pole structure.	28k
2013/14	Transformers - 2 Pole Structures	Waihaha	07Q14 Rebuild structure. Next to State Highway. Existing equipment below regulation height.	56k
2013/14	Transformers - Ground Mounted	Turangi	10S41 Install RTE switch do in conjunction with 10S42.	45k
2013/14	Transformers - Ground Mounted	Turangi	10S42 Install front access transformer with11 kV internal fusing. Do in conjunction with 10S41.	45k
2014/15	Switches	Tokaanu / Kuratau 33	5984 Switch Automation	36k
2014/15	Switches	Rangipo / Hautu	5207 Install recloser at this site.	45k
2014/15	Switchgear	Oruatua Feeder	FED417 Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	158k
2014/15	Switchgear	Oruatua	09U11 Install switchgear near or associated with 09U11.	56k
2014/15	Switchgear	Kuratau	08R20 Install transformer with RTE switch.	45k
2014/15	Transformers - 2 Pole Structures	Motuoapa	09T04 Replace with ground mounted 300 kVA. Use a refurbished transformer.	56k
2014/15	Transformers - 2 Pole Structures	Kuratau	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available.	39k
2014/15	Transformers - Ground Mounted	Turangi	10S44 Tin shed roadside. Open LV rack in tin shed, messy layout of leads. Replace with ground mounted transformer.	41k
2015/16	Line Renewal	Oruatua	417-01 11kV Line Renewal	224k
2015/16	Line Renewal	No Feeder	506-01 LV Line Renewal	186k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 11 kV breakers to split heavily loaded feeder.	155k
2015/16	Switches	Kuratau	6353 Automate recloser.	34k
2015/16	Switchgear	Kuratau	09R14 Install Xiria in association with Transformer 09R14 and work on 09R16.	45k
2015/16	Switchgear	Kuratau	09R16 Install RTE switch.	45k
2015/16	Transformers - 2 Pole Structures	Kuratau	09R27 Lift equipment on pole to above regulation height and maintain clearances.	39k
2015/16	Transformers - Ground Mounted	Turangi	10S26 Rebuild to regulations and current TLC standards.	45k
2016/17	Line Renewal	Waiotaka	427-01 11kV Line Renewal	166k
2016/17	Line Renewal	Motuoapa	425-01 11kV Line Renewal	101k
2016/17	Line Renewal	Motuoapa	425-01 LV Line Renewal	159k
2016/17	Switches	Kuratau	6355 Automate Switch	34k
2016/17	Switchgear	Rangipo / Hautu	10S03 Install switchgear	45k
2016/17	Transformers - Ground Mounted	Turangi	10S29 Rebuild to regulations and current TLC standards.	41k

TABLE 5-78: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR TOKAANU POS (WITHOUT INFLATION)

Table 5-79 lists the work that relates to Whakamaru & Mokai Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Line Renewal	Huirimu	121-02 11kV Line Renewal	110k
2012/13	Line Renewal	Tirohanga	129-01 11kV Line Renewal	181k
2012/13	Line Renewal	Wharepapa	122-08 11kV Line Renewal	77k
2012/13	Line Renewal	Tihoi	124-02 11kV Line Renewal	143k
2012/13	Line Renewal	Tirohanga	129-02 11kV Line Renewal	236k
2012/13	Line Renewal	Mokai	123-04 LV Line Renewal	7k
2012/13	Regulators	Whakamaru Feeder	FED120 Install regulator to lift voltage for irrigation pumps. Install near Kelly's Garage before the river crossing.	101k
2012/13	Regulators	Huirimu Feeder	FED121 To hold up voltage with small conductor going east back to Pureora. Needs to be close to ABS 425.	101k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Substation and 33 kV Development	Whakamaru Feeder	FED310 Regulators at Atiamuri to increase voltage. 33 kV regulator to lift 33 kV voltage levels.	281k
2012/13	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information. Year 2 revisit the need for fans.	11k
2012/13	Switches	Mokai	493 Automate switch, new pole and ENTEC switch.	34k
2012/13	Transformers - Ground Mounted	Mangakino	T706 Install a refurbished 200 kVA transformer.	45k
2013/14	Feeder Development	Mokai Feeder	FED123 Upgrade 11 kV conductor from old regulator site at the beginning of Tirohanga Road to the new substation site near the injection pumps. This work is in conjunction with the new modular substation and 33 kV line. 3 km of line to upgrade to Mink conductor.	309k
2013/14	Line Renewal	Wharepapa	122-07 11kV Line Renewal	264k
2013/14	Regulators	Wharepapa	122-03 Install regulator on Hingaia Road near T299.	101k
2013/14	Regulators	Wharepapa	122-06 Install regulator just after switch 376 on Whatauri Road.	101k
2013/14	Substation and 33 kV Development	Tirohanga Road / Marotiri	ZSub3358 Rebuild a new 33 kV line to a new modular substation. Line interconnects with 33 kV line to Marotiri and will be built on Tuaropaki Trust Land. Substation to be located on Tirohanga Road near Pumps. Work in conjunction with 11 kV conductor upgrade on Tirohanga Rd.	721k
2013/14	Substation and 33 kV Development	Tirohanga Road	Install a modular substation on Tirohanga Road near the injection pumps, in conjunction with new 33 kV line and 11 kV upgrade. Approx 100k for switchgear and 400k for modular substation.	515k
2013/14	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information. Year 2 revisit the need for fans.	34k
2013/14	Switches	Tihoi	454 Automate switch. Replace with ENTEC switch. Will require a new pole and switch.	34k
2013/14	Switches	Tirohanga	434 Automate Switch	23k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Transformers - Ground Mounted	Mangakino	T701 Check loading and replace with a refurbished I tank of a suitable size. Install a RMU with 2 fuses, one for T2316. Spread cost of RMU over T2316.	45k
2014/15	Line Renewal	Tihoi	124-03 11kV Line Renewal	104k
2014/15	Line Renewal	Huirimu	121-03 11kV Line Renewal	270k
2014/15	Switches	Pureora	423 Switch Automation	23k
2014/15	Transformers - Ground Mounted	Mangakino	T700 Rebuild to regulations and current TLC standards.	45k
2015/16	Line Renewal	Pureora	119-03 11kV Line Renewal	5k
2015/16	Line Renewal	Huirimu	121-04 11kV Line Renewal	63k
2015/16	Line Renewal	Whakamaru	120-03 11kV Line Renewal	152k
2015/16	Line Renewal	Whakamaru	120-03 LV Line Renewal	106k
2015/16	Switchgear	Whakamaru Feeder	FED120 RMU and 300 kVA transformer for T2523 and remove T2524 and T2521. Through-joint at T2523 to T2525. Replace LV cable around village with 4c cable, new 16mm N/S street light cable and TUDs pillar boxes. May need to include replacement of service-main to boxes on side of houses.	515k
2016/17	Regulators	Mokai	123-02 Install regulator on Waihora road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	101k
2016/17	Substation and 33 kV Development	Whakamaru Feeder	FED310 Install second regulator at Maraetai substation site on 33 kV line.	281k
2016/17	Transformers - 2 Pole Structures	Mangakino	T1081 Check loading; rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	56k

TABLE 5-79: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2016/17 FOR WHAKAMARU & MOKAI POS (WITHOUT INFLATION)

5.9 High Level Description of Projects Being Considered for Remainder of Planning Period

A detailed constraint analysis of the network is included in earlier sections of the Plan. These projects are modelled in detail to 2026/27 year.

Earlier sections provide in depth detail of this programme for the 2012/13 year and summary for the 2013/14 to 2016/17 years. The model is summarised in this section from 2017/18 to 2026/27. It should be noted that there are no overhead to underground conversions included in the planning period estimates.

The changes since the 2011 AMP are associated with updating expenditure to make cash flow funding possible and some delaying of capacity projects due to the 2009-2011 recession. Additional voltage regulators to improve voltages have been included in the Plan and the forecast effects of demand side management.

Table 5-80 summarises the programme total capital expenditure including renewals in the disclosure formats as described in Appendix A of the disclosure handbook.

CAPITAL EXPENDITURE PREDICTIONS FOR THE REMAINDER OF THE 15 YEAR PLANNING PERIOD (WITHOUT INFLATION)										
Capital Expenditure	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Customer Connection	1,141,863	1,084,745	1,323,447	986,637	1,380,566	986,637	986,637	1,268,014	986,637	986,637
System Growth	923,592	495,225	1,429,396	1,367,316	979,193	1,541,947	602,147	765,347	1,322,474	2,151,427
Reliability, Safety & Environment	1,109,447	818,245	1,161,526	1,089,867	973,050	534,619	1,110,319	1,267,857	630,286	540,243
Asset Replacement & Renewal excluding Line Renewals	586,438	656,187	662,924	723,997	550,373	550,373	606,648	662,924	615,937	550,373
Asset Replacement & Renewal Line Renewals	6,428,260	6,303,707	6,913,291	6,117,461	6,382,353	5,660,573	4,858,878	6,016,536	4,958,577	5,364,026
Asset Relocations	50,648	50,648	50,648	50,648	50,648	50,648	50,648	50,648	50,648	50,648
TOTALS	**10,240,248**	**9,408,757**	**11,541,232**	**10,335,926**	**10,316,184**	**9,324,798**	**8,215,278**	**10,031,327**	**8,564,558**	**9,643,354**

TABLE 5-80: SUMMARY OF CAPITAL EXPENDITURE PREDICTIONS INCLUDING RENEWALS IN DISCLOSURE FORMAT (WITHOUT INFLATION)

5.9.1 Customer Connection Projects

This expenditure will track to the number of new customers requiring connections. It will track up and down dependent on economic activity. Funding will come from the revenue these new connections will generate.

The scope of works includes supplying and installing TLC owned assets associated with new connections. The specific details of elements of this cost are listed below:

5.9.1.1 Sub transmission Customer Connection Related Development

Significant projects and summary scopes of work allowed for in the planning period 2017/18 to 2026/27 include:

- Industrial modular substation for customer in Te Kuiti to meet plant expansion.
- Industrial modular substation in the Hangatiki area for customer to meet plant expansion.
- Taharoa area Distributed Generation sites – upgrade of lines to carry generated capacity.
- Regulators on the Wairere / Gadsby 33 kV line for distributed generation to pull down voltage.

It is assumed that customers will use various technologies to reduce peaks and use non-asset solutions such as power factor correction.

5.9.1.2 General Connections Transformers and Earthing

This assumes a continuance of new connection activities and levels of funding in line with present policies. The scope of works includes supplying and installing new transformers, substations and fuses associated with new connections and upgrades of existing connections.

5.9.1.3 Subdivision Development

Assumes a continuing, but reduced, level of subdivision as compared to the exceptional years of 2007/08 to 2008/09. The scope of works includes supplying and installing new transformers, substations and fusing associated with subdivisions.

5.9.1.4 Industrial Development

Assumes a continuing, but reduced, level of industrial activity compared to the exceptional years of 2007/08 and 2008/09. It is assumed that customers will continue to consider peak reduction and on site non-asset solutions. The scope of works includes supplying and installing new transformers, substations, switchgear, cabling and fusing associated with industrial development.

5.9.2 System Growth Projects

This expenditure is for new and increased load. Projects will not be started or will be deferred if growth does not take place. Funding will come from the revenue these new connections will generate.

5.9.2.1 Sub Transmission System Growth Capital Expenditure

Significant projects and summary scope of works allowed for in the planning period 2017/18 to 2026/27 include:

- Modular substations in Whakamaru area for system growth due to irrigation.
- Modular substation in the Otorohanga area for lifestyle and dairying growth in the area.
- Modular substations at Kuratau/ Waihi for proposed distributed generation.
- Modular substation in Ranganui Rd area meat industry and dairying growth in the area.
- Additional transformer at Tawhai zone substation to supply increased load at Whakapapa ski field.
- New POS supply from Whakamaru
- Load Control plant at Mokai
- Additional capacity from Mokai.

It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions, such as power factor correction.

Figure 5-27 is a photo of a modular substation installed for a customer.

FIGURE 5-27: MODULAR SUBSTATION WITH PLANTING TO SCREEN FROM ROAD.

5.9.2.2 Voltage Support

We are continuing with the deployment of regulators, and possibly capacitors, to support network voltage. Individual sites have been identified by network analysis models. It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions.

The scope of work for most of these installations involves installing a high strength pole and two single phase regulators. Depending on the changes that occur in customer needs and our increasing understanding of network performance it is likely there will be a number of sites where capacitors will be deployed for voltage support to complement regulators.

5.9.2.3 Feeder Development

Summary scope of works allowed for in the planning period 2016/17to 2026/27 includes:

- Second cable from Tawhai Substation to Whakapapa Ski Field.
- Strengthening projects involved with supply to Ohakune.
- Strengthening of the network in the Taumarunui CBD
- Strengthening projects for urban/lifestyle development to north of Otorohanga.
- Strengthening projects in Turangi.
- Conversion of SWER systems to 3 phase lines as part of holiday home development in the Kuratau and Waihaha areas.
- Advance the 33 kV line towards Mokau to support system growth.

These projects assume increasing success of demand side management schemes by customers including the deployment of generators, (active and reactive power), for peak reduction.

5.9.3 Reliability, Safety and Environmental Projects

5.9.3.1 Reliability

The projects allowed for in the planning period 2017/18 to 2026/27 include a continuing programme of increasing network automation at a rate of about five new items of equipment annually. The specific sites have been identified and are included in plans. High level designs, evaluations and justifications have been completed.

Included in the planning is also a focus on automation of switches in the urban centres. This is to ensure faster restore times for the higher density urban population when field staff are deployed in the rural areas. The scope of works includes automating existing switches and reclosers.

Major projects programmed for these years include:

- Another mobile generator plant to reduce costs of hiring generators.
- Splitting the bus at the Borough substation to improve reliability and safety.

5.9.3.2 Hazard Elimination/Minimisation (Safety)

The programme focuses on eliminating/minimising hazards in equipment and network architecture. This mostly includes low or hazardous 2 pole structures, ground mounted transformers, service boxes and distribution switchgear. All of this equipment has been inspected, photographed and prioritised. The expenditure predictions are based on the costs of eliminating or minimising these hazards and bringing the sites up to present day industry standards. Practical and likely ways incidents or events could happen when the overall network architecture in the area is considered have also been included in the prioritisation process.

The expenditure is higher at the beginning of the period and generally ramps down. The perturbations to this trend in 2019/20, 2021/22, 2023/24 and 2024/25 are caused by scheduling this work with other work programmes. The challenge for TLC is to complete this renewal work for costs that are lower than the estimates included in this section by increasing operational efficiency and being innovative with designs and equipment selection.

The projects allowed for in the planning period 2016/16 to 2026/27 include working through the programme of listed priority equipment. The scope of works includes renewal of sub transmission components, pole structures supporting equipment, ground mounted transformers, service boxes, switchgear and other hazardous equipment.

The specific sites have been evaluated and concept designs completed. These include adding switches to underground reticulation, rebuilding hazard free transformer structures, replacing ground mounted distribution substations that have inadequate enclosures, uncovered bushings and/or poorly designed LV racks.

Major projects programmed for these years include:

- Lake Taupo 33 kV river crossing.
- A modular substation at Tuhua zone substation.
- Renewal of 33 kV circuit breakers at Mahoenui zone substation
- Renewal of switchgear at Wairere zone substation
- Renewal of Nihoniho zone substation’s fence.

5.9.3.3 Environmental

The projects allowed for in the planning period 2016/17 to 2026/27 include working through the list of non-compliant equipment. These items of equipment are listed in the earlier constraints section.

The scope of work includes mostly the installation of oil bunding/separation and earthquake restraints.

The major project programmed for this period is a modular substation north of Taumarunui as the Borough substation is in a flood zone.

5.9.4 Asset Replacement and Renewal Projects

5.9.4.1 Equipment Renewals

Major projects programmed for these years include:

- Refurbishment of Wairere zone substation's two transformers.
- Refurbishment of Mahoenui zone substation transformer.
- Refurbishment of Tawhai zone substation transformer.
- Renewal of circuit breakers at Atiamuri POS
- Renewal of circuit breakers at Maraetai zone substation.

5.9.4.2 General Equipment Renewals

Equipment renewal expenditure includes contingency amounts per annum to cover equipment failure and refurbishment, these categories are:

- SCADA
- Radio & Data communications
- Distribution Transformers renewals
- Tap-offs with new connections
- Protection, relays and equipment
- Distribution Equipment

There are specific amounts set aside for load control, Radios and SCADA for planned upgrades.

5.9.4.3 Load Control Relays

Expenditure is for the continuation with the upgrade of relays to the advanced meter type within TLC's network.

5.9.4.4 Line Renewals

Programmes based on 15 year cycle for 33 kV, 11 kV and LV lines.
The full details of the line renewal and replacement programme are discussed in the lifecycle asset management planning – section 6 of this document.

5.9.5 Asset Relocation Projects

Asset relocations are typically associated with road realignment and slips. TLC cannot forward plan for these; an allowance of $50,648 p.a. has been allocated.

5.10 Capital Expenditure Predictions for the Planning Period in Disclosure Format

Table 5-81 lists the capital expenditure predictions in disclosure format, inflation adjusted at 3% based on current dollar estimates.

	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 1 to 8							
CAPITAL EXPENDITURE PREDICTIONS	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Customer Connection	584,609	1,935,930	643,397	1,854,907	932,299	1,363,444	1,334,099	1,676,503
System Growth	1,074,436	1,056,137	116,838	337,613	713,886	1,102,817	609,064	1,810,716
Reliability, Safety & Environment	1,415,329	2,216,950	1,475,801	2,476,259	1,034,863	1,323,679	1,006,339	1,471,386
Asset Replacement & Renewal excluding Line Renewals	909,503	1,840,332	1,185,017	1,062,285	842,137	694,321	803,875	839,773
Asset Replacement & Renewal Line Renewals	5,551,158	5,733,178	6,147,033	6,485,684	6,594,948	7,675,676	7,752,765	8,757,549
Asset Relocations	52,168	53,733	55,345	57,005	58,715	60,477	62,291	64,160
Total	**9,587,202**	**12,836,259**	**9,623,430**	**12,273,753**	**10,176,849**	**12,220,414**	**11,568,433**	**14,620,087**

	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 9 to 15						
CAPITAL EXPENDITURE	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2020/21	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Customer Connection	1,287,337	1,855,364	1,365,736	1,406,708	1,862,121	1,492,376	1,537,148
System Growth	1,784,037	1,315,953	2,134,414	858,517	1,123,937	2,000,359	3,351,852
Reliability, Safety & Environment	1,422,029	1,307,698	740,038	1,583,049	1,756,422	953,363	841,681
Asset Replacement & Renewal excluding Line Renewals	944,652	739,656	761,845	864,935	973,527	931,660	857,464
Asset Replacement & Renewal Line Renewals	7,981,898	8,577,346	7,835,552	6,927,593	8,835,481	7,500,288	8,356,975
Asset Relocations	66,084	68,067	70,109	72,212	74,379	76,610	78,908
Total	**13,486,038**	**13,864,084**	**12,907,693**	**11,713,015**	**14,625,867**	**12,954,657**	**15,024,028**

TABLE 5-81: CAPITAL PREDICTIONS IN DISCLOSURE FORMAT INFLATION ADJUSTED

5.10.1 Specific projects in the planning system for the years 2017/18 to 2067/27 (years 6 to 15)

Table 5-82 lists all capital projects in TLC's forward planning system; determined in accordance with the policies and procedures determined in earlier sections. The list is ordered by across the network Non-Specific locations and Point of Supply (or GXP). The figures are in current dollar values, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
2017/18	Customer Driven Projects	Various	General Connections - Transformers	186k
2017/18	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2017/18	Customer Driven Projects	Various	Industrials - Transformers	186k
2017/18	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2017/18	Customer Driven Projects	Various	Subdivisions - Management	11k
2017/18	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2017/18	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2017/18	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2017/18	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2017/18	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	6k
2017/18	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2017/18	Network Equipment Renewal	Whole Network	Protection	11k
2017/18	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2017/18	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2017/18	Network Equipment Renewal	Whole Network	Relay Changes - Special	36k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2017/18	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2017/18	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2017/18	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2018/19	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
2018/19	Customer Driven Projects	Various	General Connections - Transformers	186k
2018/19	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2018/19	Customer Driven Projects	Various	Industrials - Transformers	186k
2018/19	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2018/19	Customer Driven Projects	Various	Subdivisions - Management	11k
2018/19	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2018/19	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2018/19	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2018/19	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2018/19	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2018/19	Network Equipment Renewal	Whole Network	Protection	11k
2018/19	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2018/19	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2018/19	Network Equipment Renewal	Whole Network	Relay Changes - Special	16k
2018/19	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2018/19	Network Equipment Renewal	Whole Network	SCADA Specific	42k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2018/19	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2019/20	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2019/20	Customer Driven Projects	Various	General Connections - Transformers	265k
2019/20	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2019/20	Customer Driven Projects	Various	Industrials - Transformers	265k
2019/20	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2019/20	Customer Driven Projects	Various	Subdivisions - Management	11k
2019/20	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2019/20	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2019/20	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2019/20	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2019/20	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2019/20	Network Equipment Renewal	Whole Network	Load Control	113k
2019/20	Network Equipment Renewal	Whole Network	Protection	11k
2019/20	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2019/20	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2019/20	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2019/20	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2019/20	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2019/20	Network Equipment Renewal	Whole Network	Transformer Renewals	338k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2020/21	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2020/21	Customer Driven Projects	Various	General Connections - Transformers	265k
2020/21	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2020/21	Customer Driven Projects	Various	Industrials - Transformers	265k
2020/21	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2020/21	Customer Driven Projects	Various	Subdivisions - Management	11k
2020/21	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2020/21	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2020/21	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2020/21	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2020/21	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2020/21	Network Equipment Renewal	Whole Network	Protection	11k
2020/21	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2020/21	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2020/21	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2020/21	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2020/21	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2020/21	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2021/22	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2021/22	Customer Driven Projects	Various	General Connections - Transformers	265k
2021/22	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Customer Driven Projects	Various	Industrials - Transformers	265k
2021/22	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2021/22	Customer Driven Projects	Various	Subdivisions - Management	11k
2021/22	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2021/22	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2021/22	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2021/22	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2021/22	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2021/22	Network Equipment Renewal	Whole Network	Protection	11k
2021/22	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2021/22	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2021/22	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2021/22	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2021/22	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2021/22	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2022/23	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2022/23	Customer Driven Projects	Various	General Connections - Transformers	265k
2022/23	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2022/23	Customer Driven Projects	Various	Industrials - Transformers	265k
2022/23	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2022/23	Customer Driven Projects	Various	Subdivisions - Management	11k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2022/23	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2022/23	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2022/23	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2022/23	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2022/23	Network Equipment Renewal	Whole Network	Protection	11k
2022/23	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2022/23	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2022/23	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2022/23	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2022/23	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2022/23	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2023/24	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2023/24	Customer Driven Projects	Various	General Connections - Transformers	265k
2023/24	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2023/24	Customer Driven Projects	Various	Industrials - Transformers	265k
2023/24	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2023/24	Customer Driven Projects	Various	Subdivisions - Management	11k
2023/24	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2023/24	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2023/24	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2023/24	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2023/24	Network Equipment Renewal	Whole Network	Distribution Equipment	56k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2023/24	Network Equipment Renewal	Whole Network	Protection	11k
2023/24	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2023/24	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2023/24	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2023/24	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2023/24	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2023/24	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2024/25	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2024/25	Customer Driven Projects	Various	General Connections - Transformers	265k
2024/25	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2024/25	Customer Driven Projects	Various	Industrials - Transformers	265k
2024/25	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2024/25	Customer Driven Projects	Various	Subdivisions - Management	11k
2024/25	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2024/25	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2024/25	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2024/25	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2024/25	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2024/25	Network Equipment Renewal	Whole Network	Load Control	113k
2024/25	Network Equipment Renewal	Whole Network	Protection	11k
2024/25	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2024/25	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2024/25	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2024/25	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2024/25	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2024/25	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2025/26	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2025/26	Customer Driven Projects	Various	General Connections - Transformers	265k
2025/26	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2025/26	Customer Driven Projects	Various	Industrials - Transformers	265k
2025/26	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2025/26	Customer Driven Projects	Various	Subdivisions - Management	11k
2025/26	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2025/26	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2025/26	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2025/26	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2025/26	Network Equipment Renewal	Whole Network	Have mobile generators to support loads. Upgrade existing generator.	169k
2025/26	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2025/26	Network Equipment Renewal	Whole Network	Protection	11k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2025/26	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2025/26	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2025/26	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2025/26	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2025/26	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2025/26	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2026/27	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
2026/27	Customer Driven Projects	Various	General Connections - Transformers	265k
2026/27	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
2026/27	Customer Driven Projects	Various	Industrials - Transformers	265k
2026/27	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
2026/27	Customer Driven Projects	Various	Subdivisions - Management	11k
2026/27	Customer Driven Projects	Various	Subdivisions - Transformers	106k
2026/27	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
2026/27	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
2026/27	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
2026/27	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2026/27	Network Equipment Renewal	Whole Network	Protection	11k
2026/27	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2026/27	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2026/27	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2026/27	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2026/27	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2026/27	Network Equipment Renewal	Whole Network	Transformer Renewals	338k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Line Renewal	Mokau	128-03 11kV Line Renewal	348k
2017/18	Line Renewal	Maihiihi	111-06 11kV Line Renewal	209k
2017/18	Line Renewal	Otorohanga	112-01 11kV Line Renewal	324k
2017/18	Line Renewal	Benneydale	103-09 11kV Line Renewal	379k
2017/18	Line Renewal	Mokau	128-10 11kV Line Renewal	261k
2017/18	Line Renewal	Te Kuiti South	104-01 11kV Line Renewal	365k
2017/18	Line Renewal	Te Kawa St 33	304-01 33kV Line Renewal	197k
2017/18	Line Renewal	Gadsby / Wairere 33	307-03 33kV Line Renewal	275k
2017/18	Line Renewal	Otorohanga	112-01 LV Line Renewal	212k
2017/18	Line Renewal	Te Kuiti South	104-01 LV Line Renewal	318k
2017/18	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Install modular substation at industrial sites. Funded through on-going charges to industrial customers.	394k
2017/18	Substation and 33 kV Development	Oparure Zone Substation	ZSub208 Install bunding, oil separation and earthquake restraints.	45k
2017/18	Switches	Otorohanga Feeder	FED112 LV Link T554 toilet block link to adjacent transformers.	113k
2017/18	Switches	McDonalds	320 Automate Switch	23k
2017/18	Transformers - 2 Pole Structures	Mokau	T2177 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - 2 Pole Structures	Te Kuiti South	T478 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
2017/18	Transformers - Ground Mounted	Otorohanga	T699 Rebuild to regulations and current TLC standards.	45k
2017/18	Transformers - Ground Mounted	Coast	T547 Rebuild to regulations and current TLC standards.	45k
2018/19	Line Renewal	Aria	114-01 11kV Line Renewal	233k
2018/19	Line Renewal	Rangitoto	106-07 11kV Line Renewal	276k
2018/19	Line Renewal	Rangitoto	106-02 11kV Line Renewal	30k
2018/19	Line Renewal	Te Kuiti South	104-02 11kV Line Renewal	350k
2018/19	Line Renewal	Oparure	107-08 11kV Line Renewal	207k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Line Renewal	Rangitoto	106-01 11kV Line Renewal	160k
2018/19	Line Renewal	Benneydale	103-09 11kV Line Renewal	379k
2018/19	Line Renewal	Taharoa B 33	302-01 33kV Line Renewal	554k
2018/19	Line Renewal	Gadsby / Wairere 33	307-01 33kV Line Renewal	121k
2018/19	Line Renewal	Aria	114-01 LV Line Renewal	21k
2018/19	Line Renewal	Rangitoto	106-01 LV Line Renewal	127k
2018/19	Line Renewal	Rangitoto	106-07 LV Line Renewal	16k
2018/19	Regulators	Mokau Feeder	FED128 Before Mokau at old killing house site.	101k
2018/19	Substation and 33 kV Development	Taharoa A Feeder	FED301 Upgrade line to higher transmission voltage and capacity.	337k
2018/19	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Refurbish transformer (T1)	90k
2018/19	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Install oil separation.	17k
2018/19	Switches	Hangatiki East	336 Automate Switch	39k
2018/19	Transformers - 2 Pole Structures	Mahoenui	T1692 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2018/19	Transformers - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design.	45k
2018/19	Transformers - 2 Pole Structures	Mokau	T2194 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
2018/19	Transformers - Ground Mounted	Oparure	T9 Rebuild to regulations and current TLC standards.	45k
2019/20	Feeder Development	Mokau Feeder	FED128 Mokau Generator. Add remotely controlled diesel gas injection for holiday periods and during shutdown interruptions.	338k
2019/20	Line Renewal	Coast	125-01 11kV Line Renewal	270k
2019/20	Line Renewal	Piopio	116-02 11kV Line Renewal	186k
2019/20	Line Renewal	Mahoenui	113-01 11kV Line Renewal	213k
2019/20	Line Renewal	Te Mapara	117-01 11kV Line Renewal	301k
2019/20	Line Renewal	Mokauiti	115-01 11kV Line Renewal	129k
2019/20	Line Renewal	Piopio	116-01 11kV Line Renewal	406k
2019/20	Line Renewal	Taharoa A 33	301-01 33kV Line Renewal	554k
2019/20	Line Renewal	Waitete 33	306-01 33kV Line Renewal	233k
2019/20	Line Renewal	Gadsby / Wairere 33	307-03 33kV Line Renewal	275k
2019/20	Line Renewal	Piopio	116-02 LV Line Renewal	133k
2019/20	Line Renewal	Coast	125-01 LV Line Renewal	5k
2019/20	Regulators	Piopio Feeder	FED116 Prior to Piopio township.	96k
2019/20	Regulators	Mahoenui Feeder	FED113 Mainly for backup of Mokau Feeder when 33 kV is out.	96k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Substation and 33 kV Development	Taharoa A Feeder	FED301 Upgrade line to higher transmission voltage and capacity.	337k
2019/20	Switches	Maihiihi	127 Replace Recloser	45k
2019/20	Switches	Hangatiki East	361 Automate Switch	23k
2019/20	Switches	Mahoenui	1343 Replace Recloser	45k
2019/20	Transformers - 2 Pole Structures	Tihoi	T1618 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
2019/20	Transformers - Ground Mounted	Mokau	T2155 Rebuild to regulations and current TLC standards.	45k
2019/20	Transformers - Ground Mounted	Mokau	T2154 Transformer upgrade.	45k
2019/20	Transformers - Ground Mounted	Mokau	T2140 Transformer upgrade.	45k
2019/20	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	45k
2019/20	Transformers - Ground Mounted	Coast	T640 Rebuild to regulations and current TLC standards.	45k
2020/21	Line Renewal	Caves	101-04 11kV Line Renewal	85k
2020/21	Line Renewal	Mokau	128-05 11kV Line Renewal	184k
2020/21	Line Renewal	Rural	126-01 11kV Line Renewal	75k
2020/21	Line Renewal	Caves	101-03 11kV Line Renewal	42k
2020/21	Line Renewal	Caves	101-02 11kV Line Renewal	71k
2020/21	Line Renewal	Caves	101-01 11kV Line Renewal	168k
2020/21	Line Renewal	Caves	101-05 11kV Line Renewal	87k
2020/21	Line Renewal	Mokau	128-02 11kV Line Renewal	203k
2020/21	Line Renewal	Caves	101-07 11kV Line Renewal	50k
2020/21	Line Renewal	Caves	101-06 11kV Line Renewal	66k
2020/21	Line Renewal	Caves	101-08 11kV Line Renewal	34k
2020/21	Line Renewal	Gadsby Rd 33	305-02 33kV Line Renewal	248k
2020/21	Line Renewal	Gadsby / Wairere 33	307-02 33kV Line Renewal	92k
2020/21	Line Renewal	Mokau	128-02 LV Line Renewal	27k
2020/21	Line Renewal	Rural	126-01 LV Line Renewal	5k
2020/21	Line Renewal	Mokau	128-05 LV Line Renewal	93k
2020/21	Regulators	Mokauiti	115-03 Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	96k
2020/21	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Renew switchgear and improve protection schemes.(33 kV)	338k
2020/21	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T2). Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.	90k
2020/21	Switches	Mahoenui	1512 Upgrade recloser	45k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2020/21	Transformers - Ground Mounted	Te Kuiti South	T10 Rebuild to regulations and current TLC standards.	56k
2020/21	Transformers - Ground Mounted	Gravel Scoop	T1007 Rebuild to regulations and current TLC standards.	56k
2020/21	Transformers - Ground Mounted	Rural	T1390 Rebuild to regulations and current TLC standards.	45k
2021/22	Line Renewal	Te Mapara	117-02 11kV Line Renewal	207k
2021/22	Line Renewal	Maihiihi	111-01 11kV Line Renewal	62k
2021/22	Line Renewal	Maihiihi	111-03 11kV Line Renewal	162k
2021/22	Line Renewal	Maihiihi	111-10 11kV Line Renewal	83k
2021/22	Line Renewal	Maihiihi	111-02 11kV Line Renewal	67k
2021/22	Line Renewal	Maihiihi	111-04 11kV Line Renewal	232k
2021/22	Line Renewal	Gadsby Rd 33	305-03 33kV Line Renewal	59k
2021/22	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	266k
2021/22	Line Renewal	Taharoa B 33	302-02 33kV Line Renewal	478k
2021/22	Line Renewal	Maihiihi	111-02 LV Line Renewal	95k
2021/22	Line Renewal	Maihiihi	111-01 LV Line Renewal	32k
2021/22	Line Renewal	Maihiihi	111-00 LV Line Renewal	13k
2021/22	Substation and 33 kV Development	Hangatiki Zone Substation	ZSub204 Diversify and encourage industrials downstream to install 33/11kV modular substations on their sites. Oyma container sub. Customer funds costs through on-going charges.	394k
2021/22	Switches	Waitomo	182 Automate Switch	23k
2021/22	Transformers - 2 Pole Structures	Caves	T1185 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2021/22	Transformers - Ground Mounted	Oparure	T1043 Rebuild to regulations and current TLC standards.	56k
2021/22	Transformers - Ground Mounted	Otorohanga	T170 Rebuild to regulations and current TLC standards.	45k
2021/22	Transformers - Ground Mounted	Rural	T1367 Rebuild to regulations and current TLC standards.	45k
2022/23	Line Renewal	Piopio	116-04 11kV Line Renewal	456k
2022/23	Line Renewal	Maihiihi	111-12 11kV Line Renewal	250k
2022/23	Line Renewal	Maihiihi	111-05 11kV Line Renewal	136k
2022/23	Line Renewal	Oparure	107-03 11kV Line Renewal	119k
2022/23	Line Renewal	Oparure	107-07 11kV Line Renewal	329k
2022/23	Line Renewal	McDonalds	110-01 11kV Line Renewal	41k
2022/23	Line Renewal	Hangatiki East	102-01 11kV Line Renewal	117k
2022/23	Line Renewal	Hangatiki East	102-02 11kV Line Renewal	166k
2022/23	Line Renewal	Oparure	107-04 11kV Line Renewal	316k
2022/23	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	133k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Line Renewal	Oparure	107-04 LV Line Renewal	8k
2022/23	Line Renewal	Gravel Scoop	109-10 LV Line Renewal	64k
2022/23	Line Renewal	Gravel Scoop	109-01 LV Line Renewal	42k
2022/23	Line Renewal	McDonalds	110-01 LV Line Renewal	13k
2022/23	Substation and 33 kV Development	Gadsby Road Zone Substation	ZSub205 Modify existing site by installing better earthquake restraints.	34k
2022/23	Switches	Gravel Scoop	304 Install Automated Feeder tie	28k
2022/23	Transformers - Ground Mounted	Rural	T1559 Rebuild to regulations and current TLC standards.	45k
2022/23	Transformers - Ground Mounted	Benneydale	T2598 Rebuild to regulations and current TLC standards.	45k
2023/24	Line Renewal	Gravel Scoop	109-02 11kV Line Renewal	142k
2023/24	Line Renewal	Te Mapara	117-03 11kV Line Renewal	227k
2023/24	Line Renewal	Gravel Scoop	109-01 11kV Line Renewal	17k
2023/24	Line Renewal	Mokau	128-01 11kV Line Renewal	547k
2023/24	Line Renewal	Gravel Scoop	109-03 11kV Line Renewal	185k
2023/24	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	133k
2023/24	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Refurbish transformer	56k
2023/24	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Increase the height of the oil bund and install oil separation.	17k
2023/24	Switches	Otorohanga	316 Change switch to a recloser.	45k
2023/24	Transformers - Ground Mounted	Otorohanga	T1552 Rebuild to regulations and current TLC standards.	56k
2024/25	Line Renewal	Coast	125-02 11kV Line Renewal	314k
2024/25	Line Renewal	Te Mapara	117-05 11kV Line Renewal	212k
2024/25	Line Renewal	Piopio	116-03 11kV Line Renewal	72k
2024/25	Line Renewal	Otorohanga	112-02 11kV Line Renewal	63k
2024/25	Line Renewal	Otorohanga	112-03 11kV Line Renewal	158k
2024/25	Line Renewal	Coast	125-04 11kV Line Renewal	191k
2024/25	Line Renewal	Rangitoto	106-04 11kV Line Renewal	500k
2024/25	Line Renewal	Mahoenui 33	309-02 33kV Line Renewal	121k
2024/25	Line Renewal	Mahoenui 33	309-01 33kV Line Renewal	121k
2024/25	Line Renewal	Gadsby Rd 33	305-01 33kV Line Renewal	262k
2024/25	Regulators	Caves Feeder	FED101 Depends on tourism growth in area.	96k
2024/25	Substation and 33 kV Development	Gadsby / Wairere Feeder	FED307 Allow for full output of proposed schemes. Install additional regulators at Wairere to pull down voltage.	281k
2024/25	Switches	Rangitoto	224 Install a recloser	45k
2025/26	Line Renewal	Mahoenui	113-02 11kV Line Renewal	53k
2025/26	Line Renewal	McDonalds	110-02 11kV Line Renewal	155k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2025/26	Line Renewal	Aria	114-02 11kV Line Renewal	84k
2025/26	Line Renewal	Maihiihi	111-09 11kV Line Renewal	73k
2025/26	Line Renewal	Benneydale	103-03 11kV Line Renewal	10k
2025/26	Line Renewal	Benneydale	103-01 11kV Line Renewal	5k
2025/26	Line Renewal	Waitomo	108-02 11kV Line Renewal	145k
2025/26	Line Renewal	Rangitoto	106-06 11kV Line Renewal	447k
2025/26	Line Renewal	Benneydale	103-02 11kV Line Renewal	11k
2025/26	Line Renewal	Waitomo	108-01 11kV Line Renewal	56k
2025/26	Line Renewal	Mokauiti	115-02 11kV Line Renewal	165k
2025/26	Line Renewal	Maihiihi	109-09 11kV Line Renewal	114k
2025/26	Regulators	Gravel Scoop Feeder	FED109 Otewa road just before Barber. Will mainly be used when tying to Rangitoto and Maihiihi.	96k
2025/26	Substation and 33 kV Development	Mahoenui Feeder	FED309 Built out 33 kV line as load grows in Mokau area.	675k
2025/26	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Replace fault thrower with CB 33 kV.	68k
2025/26	Switches	Mokau	1626 Change sectionaliser to recloser.	45k
2025/26	Switches	Te Kuiti South	242 Automate Switch	23k
2025/26	Transformers - Ground Mounted	Te Kuiti South	T1447 Rebuild to regulations and current TLC standards.	34k
2026/27	Line Renewal	Otorohanga	112-04 11kV Line Renewal	98k
2026/27	Line Renewal	Mokau	128-04 11kV Line Renewal	94k
2026/27	Line Renewal	Oparure	107-02 11kV Line Renewal	109k
2026/27	Line Renewal	Mokauiti	115-03 11kV Line Renewal	275k
2026/27	Line Renewal	Coast	125-03 11kV Line Renewal	193k
2026/27	Line Renewal	Benneydale	103-04 11kV Line Renewal	415k
2026/27	Line Renewal	Oparure	107-01 11kV Line Renewal	72k
2026/27	Line Renewal	Maihiihi	111-07 11kV Line Renewal	203k
2026/27	Line Renewal	Coast	125-03 LV Line Renewal	14k
2026/27	Line Renewal	Oparure	107-02 LV Line Renewal	166k
2026/27	Regulators	Hangatiki East Feeder	FED102 Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	96k
2026/27	Substation and 33 kV Development	Te Waireka Zone Substation	ZSub203 Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1463k
2026/27	Transformers - Ground Mounted	Waitomo	T1003 Rebuild to regulations and current TLC standards.	45k
2026/27	Transformers - Ground Mounted	Otorohanga	T1174 Rebuild to regulations and current TLC standards.	45k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
2017/18	Switchgear	National Park	15L07 Install switchgear	45k
2017/18	Switchgear	Chateau	16N01 Add 11 kV switchgear to transformer.	45k
2018/19	Line Renewal	National Park	411-01 11kV Line Renewal	147k
2018/19	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
2018/19	Line Renewal	Chateau	419-01 11kV Line Renewal	143k
2018/19	Line Renewal	National Park	411-01 LV Line Renewal	191k
2018/19	Switchgear	Chateau	16N02 Add 11 kV switchgear to transformer.	45k
2018/19	Transformers - 2 Pole Structures	National Park	16L02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - Ground Mounted	Chateau	16N05 Rebuild to regulations and current TLC standards.	45k
2019/20	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
2019/20	Line Renewal	Chateau	419-01 11kV Line Renewal	143k
2019/20	Line Renewal	National Park / Kuratau 33	609-03 33kV Line Renewal	576k
2019/20	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Install a second transformer. Use a Transformer out of Turangi.	675k
2019/20	Switchgear	Chateau	16N28 Add 11 kV switchgear to transformer.	45k
2019/20	Switchgear	Chateau	16N29 Add 11 kV switchgear to transformer.	45k
2019/20	Transformers - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transfer structure to make safer. Investigate a refurnished 33 kV / 400 v transformer. A lot of children visit this area, structure needs to be made safe.	62k
2020/21	Line Renewal	Otukou	418-01 11kV Line Renewal	335k
2020/21	Line Renewal	National Park / Kuratau 33	609-01 33kV Line Renewal	266k
2020/21	Line Renewal	Otukou	418-01 LV Line Renewal	64k
2020/21	Switches	National Park	5146 Install recloser	45k
2020/21	Switchgear	Chateau	15N11 Add 11 kV switchgear to transformer.	45k
2020/21	Transformers - 2 Pole Structures	Otukou	12O01 Renew Structure. This transformer needs to be checked for loading.	39k
2021/22	Feeder Development	Chateau Feeder	FED419 Cable from Tavern to Water Tower, 2nd Cable.	338k
2021/22	Line Renewal	National Park / Kuratau 33	609-02 33kV Line Renewal	548k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Switchgear	Chateau	08I03 Add 11 kV switchgear to transformer	45k
2021/22	Transformers - 2 Pole Structures	Raurimu	T4077 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2022/23	Switchgear	Chateau	08I34 Add 11 kV switchgear to transformer	45k
2023/24	Substation and 33 kV Development	Otukou Zone Substation	ZSub512 Modify existing site by installing bunding, oil separation and earthquake restraints.	68k
2023/24	Switchgear	Chateau	15N02 Add 11 kV switchgear to transformer	45k
2023/24	Transformers - 2 Pole Structures	National Park	15K06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
2023/24	Transformers - Ground Mounted	Otukou	12N08 Renew with modern equivalent	45k
2023/24	Transformers - Ground Mounted	Chateau	16N04 Rebuild to regulations and current TLC standards.	28k
2024/25	Feeder Development	Chateau Feeder	FED419 Add second cable from Tawhai to Tavern	563k
2024/25	Switchgear	Chateau	15N09 Add 11 kV switchgear to transformer	45k
2024/25	Transformers - Ground Mounted	Chateau	16N06 Rebuild to regulations and current TLC standards.	51k
2024/25	Transformers - Ground Mounted	Chateau	16N07 Rebuild to regulations and current TLC standards.	51k
2025/26	Line Renewal	National Park	411-03 11kV Line Renewal	295k
2025/26	Line Renewal	Raurimu	410-01 11kV Line Renewal	355k
2025/26	Line Renewal	Raurimu	410-01 LV Line Renewal	48k
2026/27	Line Renewal	Raurimu	410-01 11kV Line Renewal	355k
2026/27	Switchgear	Chateau	15N12 Add 11 kV switchgear to transformer.	45k
2026/27	Transformers - Ground Mounted	National Park	14L05 Rebuild to regulations and current TLC standards.	45k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Regulators	Tangiwai Feeder	FED416 Assumes new Tangiwai supply from Transpower, locate at Rangataua.	107k
2017/18	Switchgear	Tangiwai	20L44 Install switchgear RMU	45k
2017/18	Switchgear	Tangiwai	09R11 Install switchgear	45k
2017/18	Switchgear	Ohakune Town	20L18 Install switchgear	45k
2017/18	Transformers - 2 Pole Structures	Turoa	20L31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
2018/19	Switchgear	Ohakune Town	T4199 Install switchgear	45k
2018/19	Switchgear	Tangiwai	20L46 Install switchgear, RMU.	45k
2018/19	Transformers - 2 Pole Structures	Turoa	20M01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	51k
2019/20	Line Renewal	Turoa	415-04 11kV Line Renewal	101k
2019/20	Transformers - 2 Pole Structures	Turoa	20L19 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
2020/21	Feeder Development	Ohakune Town Feeder	FED414 Install under ground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm Al XLPE.	103k
2020/21	Feeder Development	Turoa	415-04 This is for the re-conductoring of the feeder tie to Tangiwai between switch 5695 to 6323 & 6324 to 5680. Upgrade conductor to Mink or equivalent AAAC.	567k
2020/21	Line Renewal	Turoa	415-04 11kV Line Renewal	88k
2020/21	Switches	Turoa	5695 Automate Switch	45k
2020/21	Switchgear	Turoa	17N01 Install switchgear	45k
2021/22	Switchgear	Turoa	17N02 Install switchgear	45k
2021/22	Switchgear	Turoa Feeder	FED415 Mechanical cable protection required for cable to ski fields as it is beside the road and inadequately protected.	68k
2022/23	Line Renewal	Tangiwai	416-02 11kV Line Renewal	67k
2022/23	Line Renewal	Tangiwai	416-01 11kV Line Renewal	187k
2022/23	Line Renewal	Tangiwai	416-02 LV Line Renewal	93k
2023/24	Line Renewal	Tangiwai	416-03 11kV Line Renewal	222k
2023/24	Line Renewal	Tangiwai	416-03 LV Line Renewal	27k
2024/25	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k
2025/26	Line Renewal	Turoa	415-01 11kV Line Renewal	561k
2025/26	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k
2025/26	Transformers - 2 Pole Structures	Tangiwai	20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	56k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2026/27	Line Renewal	Turoa	415-02 11kV Line Renewal	43k
2026/27	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k
2026/27	Line Renewal	Turoa	415-01 11kV Line Renewal	561k
2026/27	Transformers - 2 Pole Structures	Turoa	20K09 Ground mount with 100 kVA transformer.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
2017/18	Line Renewal	Ohura	413-07 11kV Line Renewal	136k
2017/18	Line Renewal	Nihoniho 33	603-02 33kV Line Renewal	302k
2017/18	Switches	Southern	5136 Automate Switch	45k
2017/18	Switches	Matapuna	5357 Automate Switch	45k
2017/18	Transformers - 2 Pole Structures	Western	08H03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - 2 Pole Structures	Ongarue	02K16 Rebuild structure 11 kV bushing are below regulation height.	56k
2017/18	Transformers - 2 Pole Structures	Ohura	07D08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - Ground Mounted	Matapuna	01B24 Rebuild to regulations and current TLC standards.	45k
2018/19	Line Renewal	Southern	409-01 11kV Line Renewal	339k
2018/19	Line Renewal	Manunui	408-01 11kV Line Renewal	302k
2018/19	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
2018/19	Line Renewal	Nihoniho 33	603-01 33kV Line Renewal	273k
2018/19	Line Renewal	Manunui	408-01 LV Line Renewal	111k
2018/19	Switches	Matapuna	1.5 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU.	26k
2018/19	Switches	Matapuna	1.6 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU	26k
2018/19	Switches	Matapuna	1.7 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU	26k
2018/19	Transformers - 2 Pole Structures	Hakiaha	01A31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - 2 Pole Structures	Manunui	08J07 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - 2 Pole Structures	Southern	11K11 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - Ground Mounted	Matapuna	01A70 Rebuild to regulations and current TLC standards.	45k
2019/20	Line Renewal	Manunui	408-02 11kV Line Renewal	396k
2019/20	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
2019/20	Line Renewal	Northern	402-01 11kV Line Renewal	597k
2019/20	Line Renewal	Southern	409-01 11kV Line Renewal	339k
2019/20	Line Renewal	Northern	402-01 LV Line Renewal	212k
2019/20	Line Renewal	Manunui	408-02 LV Line Renewal	27k
2019/20	Transformers - 2 Pole Structures	Southern	10K14 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2019/20	Transformers - 2 Pole Structures	Nihoniho	06E01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2019/20	Transformers - 2 Pole Structures	Matapuna	01A75 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2019/20	Transformers - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	45k
2019/20	Transformers - 2 Pole Structures	Manunui	08J10 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
2019/20	Transformers - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	51k
2020/21	Line Renewal	Matapuna	404-01 11kV Line Renewal	521k
2020/21	Line Renewal	Northern	402-02 11kV Line Renewal	584k
2020/21	Line Renewal	Manunui	408-02 11kV Line Renewal	396k
2020/21	Line Renewal	Southern	409-05 11kV Line Renewal	331k
2020/21	Line Renewal	Matapuna	404-01 LV Line Renewal	338k
2020/21	Regulators	Ohura Feeder	FED413 One regulator for Ohura assuming that the coal mine venture goes ahead.	96k
2020/21	Switchgear	Northern	01A52 Install switchgear	45k
2020/21	Transformers - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	49k
2020/21	Transformers - 2 Pole Structures	Southern	09K02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2020/21	Transformers - 2 Pole Structures	Ohura	07D03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2021/22	Line Renewal	Tuhua	422-01 11kV Line Renewal	541k
2021/22	Line Renewal	Manunui	408-03 11kV Line Renewal	139k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Line Renewal	Northern	402-03 11kV Line Renewal	402k
2021/22	Line Renewal	Tuhua	422-01 LV Line Renewal	10k
2021/22	Regulators	Northern Feeder	FED402 By High School Depends on load growth.	96k
2021/22	Regulators	Ongarue	421-01 Install Regulator at State Highway 4 near switch 6640.	96k
2021/22	Substation and 33 kV Development	Borough Zone Substation	ZSub508 Diversify with modular substations. Container substation above slip on main road.	377k
2021/22	Switches	Hakiaha	5.19 Install Recloser	45k
2022/23	Line Renewal	Southern	409-04 11kV Line Renewal	60k
2022/23	Line Renewal	Southern	409-03 11kV Line Renewal	96k
2022/23	Line Renewal	Northern	402-04 11kV Line Renewal	247k
2022/23	Line Renewal	Ohura	413-02 11kV Line Renewal	316k
2022/23	Line Renewal	Southern	409-02 11kV Line Renewal	95k
2022/23	Line Renewal	Southern	409-02 LV Line Renewal	53k
2022/23	Line Renewal	Southern	409-04 LV Line Renewal	93k
2022/23	Line Renewal	Ohura	413-02 LV Line Renewal	127k
2022/23	Line Renewal	Southern	409-03 LV Line Renewal	53k
2022/23	Regulators	Western	403-02 Install regulation to accommodate increased load due to the subdivisions of land for lifestyle blocks along River Road and the surround areas.	96k
2022/23	Regulators	Ohura Feeder	FED413 Second Regulator assuming coal mine goes ahead.	96k
2022/23	Switches	Ohura	5758 Upgrade sectionaliser to modern type of recloser.	45k
2022/23	Transformers - 2 Pole Structures	Ohura	07D16 Replace with standard single pole isolating SWER structure.	39k
2022/23	Transformers - 2 Pole Structures	Southern	12K08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2022/23	Transformers - 2 Pole Structures	Ohura	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	39k
2022/23	Transformers - Ground Mounted	Northern	T4025 Rebuild to regulations and current TLC standards.	45k
2023/24	Line Renewal	Northern	402-04 11kV Line Renewal	247k
2023/24	Line Renewal	Ohura	413-01 11kV Line Renewal	133k
2023/24	Line Renewal	Manunui	408-04 11kV Line Renewal	231k
2023/24	Line Renewal	Manunui	408-04 LV Line Renewal	27k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Switches	Hakiaha Feeder	FED401 Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	131k
2023/24	Switches	Northern	5119 Upgrade recloser to new type.	45k
2023/24	Switches	Northern	5164 Upgrade recloser to new type of equipment.	45k
2023/24	Switchgear	Northern	07I14 Install switchgear	45k
2023/24	Transformers - 2 Pole Structures	Ohura	09C05 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2023/24	Transformers - Ground Mounted	Northern	07I12 Rebuild to regulations and current TLC standards.	45k
2023/24	Transformers - Ground Mounted	Matapuna	01A36 Rebuild to regulations and current TLC standards.	56k
2024/25	Line Renewal	Western	403-02 11kV Line Renewal	460k
2024/25	Line Renewal	Western	403-01 11kV Line Renewal	23k
2024/25	Line Renewal	Manunui	408-05 11kV Line Renewal	346k
2024/25	Line Renewal	Nihoniho	412-01 11kV Line Renewal	233k
2024/25	Line Renewal	Western	403-01 LV Line Renewal	74k
2024/25	Substation and 33 kV Development	Nihoniho Zone Substation	ZSub503 Replace fence and upgrade transformer.	225k
2024/25	Substation and 33 kV Development	Tuhua Zone Substation	ZSub502 Replace with modular substation.	382k
2024/25	Switchgear	Western	08I31 Install RMU	45k
2024/25	Switchgear	Northern	08I19 Install switchgear	45k
2024/25	Transformers - 2 Pole Structures	Ohura	07D11 Rebuild structure with standard single pole isolating SWER transformer structure.	39k
2024/25	Transformers - 2 Pole Structures	Ohura	T4130 Rebuild site, two SWER transformers. On site visit needed for design. Cost split between T4130 and 10E09.	39k
2025/26	Line Renewal	Hakiaha	401-02 11kV Line Renewal	122k
2025/26	Regulators	Southern Feeder	FED409 Growth in dairying and irrigation along state highway just before Otapouri road. Will help lift voltage at Owhango for subdivision growth.	101k
2025/26	Switches	Ongarue	5462 Change sectionaliser to recloser.	45k
2025/26	Transformers - Ground Mounted	Northern	01A48 Rebuild to regulations and current TLC standards.	56k
2025/26	Transformers - Ground Mounted	Matapuna	01B25 Rebuild to regulations and current TLC standards.	34k
2025/26	Transformers - Ground Mounted	Matapuna	01B21 Rebuild to regulations and current TLC standards.	34k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2025/26	Transformers - Ground Mounted	Matapuna	01B20 Rebuild to regulations and current TLC standards.	34k
2025/26	Transformers - Ground Mounted	Western	08I08 Rebuild to regulations and current TLC standards.	34k
2026/27	Line Renewal	Ongarue	421-01 11kV Line Renewal	428k
2026/27	Line Renewal	Ohura	413-06 11kV Line Renewal	182k
2026/27	Line Renewal	Southern	409-06 11kV Line Renewal	71k
2026/27	Regulators	Matapuna Feeder	FED404 Install Regulator on Taupo Road to boast voltage for back feeds and customers further down Taupo Road.	96k
2026/27	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Install reactive power capacitors.	103k
2026/27	Switches	Hakiaha	5.4 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
2026/27	Switches	Hakiaha	5.3 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
2026/27	Switches	Hakiaha	5.23 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
2026/27	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes, cable unprotected.	45k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Line Renewal	Kuratau	406-03 11kV Line Renewal	239k
2017/18	Line Renewal	Kuratau	406-03 LV Line Renewal	106k
2017/18	Switches	Kuratau	5921 Automate Switch	34k
2017/18	Switchgear	Waihaha	07R13 Install RMU	45k
2017/18	Transformers - Ground Mounted	Turangi	10S39 Rebuild to regulations and current TLC standards.	45k
2018/19	Line Renewal	Tokaanu	420-01 11kV Line Renewal	29k
2018/19	Line Renewal	No Feeder	507-01 LV Line Renewal	53k
2018/19	Switches	Kuratau	6557 Automate Switch	34k
2018/19	Switchgear	Kuratau	10S41 Install switchgear	45k
2018/19	Transformers - Ground Mounted	Rangipo / Hautu	11S16 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Motuoapa	T4104 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Turangi	10S24 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Kuratau	08R22 Rebuild to regulations and current TLC standards.	3k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Feeder Development	Waihaha Feeder	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	225k
2019/20	Switches	Turangi	5209 Install Xiria Switch or similar at this point.	68k
2019/20	Switches	Hirangi	6186 Install remote control on this switch so can tie Turangi and Hirangi feeders together.	11k
2019/20	Switches	Turangi Feeder	FED423 Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40.	281k
2020/21	Feeder Development	Kuratau Feeder	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	56k
2020/21	Line Renewal	Waihaha	426-01 11kV Line Renewal	11k
2020/21	Line Renewal	Waihaha	426-02 11kV Line Renewal	109k
2020/21	Line Renewal	Tokaanu / Kuratau 33	607-02 33kV Line Renewal	296k
2020/21	Switchgear	Rangipo / Hautu Feeder	FED424 Hazard from Genesis 33 kV line crossing.	56k
2020/21	Transformers - 2 Pole Structures	Waihaha	04Q06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2020/21	Transformers - 2 Pole Structures	Oruatua	09U12 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
2021/22	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
2021/22	Substation and 33 kV Development	Kuratau Zone Substation	ZSub509 Put in a modular substation at end of network close to an existing 33kV line.	450k
2021/22	Switchgear	Kuratau	08R08 Install switchgear	45k
2021/22	Switchgear	Turangi	10S38 Install switchgear	45k
2021/22	Transformers - 2 Pole Structures	Kuratau	09R28 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2022/23	Feeder Development	Kuratau Feeder	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	56k
2022/23	Feeder Development	Waihaha Feeder	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	169k
2022/23	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
2022/23	Line Renewal	Rangipo / Hautu	424-02 11kV Line Renewal	111k
2022/23	Line Renewal	Kuratau	406-02 11kV Line Renewal	262k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Line Renewal	Kuratau	406-02 LV Line Renewal	127k
2022/23	Switches	Rangipo / Hautu	5963 Upgrade recloser to modern equivalent.	39k
2022/23	Switchgear	Rangipo / Hautu	10S13 Install switchgear	45k
2022/23	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Rebuild to regulations and current TLC standards.	45k
2023/24	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
2023/24	Substation and 33 kV Development	Lake Taupo Feeder	FED606 Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues.	338k
2024/25	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
2024/25	Switches	Turangi Feeder	FED423 Develop LV links through the town.	113k
2024/25	Switchgear	Rangipo / Hautu	10S49 11 kV Cable hard on to 11 kV line, replace pole fit DDO's or Vertical ABS and fuses.	23k
2024/25	Transformers - Ground Mounted	Turangi	10S30 Rebuild to regulations and current TLC standards.	41k
2024/25	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Rebuild to regulations and current TLC standards.	34k
2025/26	Line Renewal	Rangipo / Hautu	424-01 11kV Line Renewal	391k
2025/26	Line Renewal	Turangi 33	605-01 33kV Line Renewal	80k
2025/26	Line Renewal	Lake Taupo 33	606-02 33kV Line Renewal	67k
2025/26	Line Renewal	Hirangi	405-01 LV Line Renewal	48k
2025/26	Line Renewal	Rangipo / Hautu	424-01 LV Line Renewal	221k
2026/27	Line Renewal	Rangipo / Hautu	424-03 11kV Line Renewal	126k
2026/27	Line Renewal	Hirangi	405-01 11kV Line Renewal	32k
2026/27	Line Renewal	Lake Taupo 33	606-01 33kV Line Renewal	72k
2026/27	Switches	Rangipo / Hautu Feeder	FED424 Add LV links through town.	113k
2026/27	Transformers - Ground Mounted	Tokaanu	10R20 Rebuild to regulations and current TLC standards.	45k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Feeder Development	Mokai Feeder	FED123 Re-conductor Tirohanga Road from new substation site near injection pumps to Okama Road. 7 km of line to Mink. This allows for better back feed options and more security of supply.	721k
2017/18	Line Renewal	Wharepapa	122-01 11kV Line Renewal	235k
2017/18	Line Renewal	Wharepapa	122-02 11kV Line Renewal	462k
2017/18	Line Renewal	Whakamaru	120-01 11kV Line Renewal	339k
2017/18	Line Renewal	Mangakino	118-01 11kV Line Renewal	364k
2017/18	Line Renewal	Mangakino	118-01 LV Line Renewal	133k
2017/18	Regulators	Pureora Feeder	FED119 Close to Crusaders Meats 4th Regulator for deer plant.	96k
2017/18	Switches	Mangakino	463 Automate Switch	23k
2018/19	Line Renewal	Wharepapa	122-06 11kV Line Renewal	292k
2018/19	Line Renewal	Whakamaru	120-02 11kV Line Renewal	221k
2018/19	Line Renewal	Wharepapa	122-03 11kV Line Renewal	255k
2018/19	Line Renewal	Wharepapa	122-04 11kV Line Renewal	248k
2018/19	Substation and 33 kV Development	Mokai Point of Supply	ZSub3358 Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	394k
2019/20	Line Renewal	Huirimu	121-01 11kV Line Renewal	245k
2019/20	Line Renewal	Tihoi	124-00 11kV Line Renewal	10k
2019/20	Line Renewal	Tihoi	124-01 11kV Line Renewal	166k
2019/20	Line Renewal	Whakamaru	120-05 11kV Line Renewal	56k
2019/20	Line Renewal	Whakamaru 33	310-01 33kV Line Renewal	118k
2020/21	Line Renewal	Whakamaru 33	310-03 33kV Line Renewal	269k
2020/21	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Diversify off site with a modular substation near Ranganui Road.	450k
2020/21	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Replace due to age reliability and condition with new type of circuit breaker.	84k
2021/22	Line Renewal	Pureora	119-02 11kV Line Renewal	673k
2021/22	Line Renewal	Whakamaru	120-04 11kV Line Renewal	866k
2021/22	Line Renewal	Whakamaru	120-02 LV Line Renewal	106k
2022/23	Line Renewal	Whakamaru	120-06 11kV Line Renewal	142k
2022/23	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Supply from Transpower at Whakamaru on the 220 kV or Mokai 110 kV supply connection at Whakamaru.	1126k
2023/24	Feeder Development	Tirohanga Feeder	FED129 More Feeder ties and a new modular substation at Mine road.	506k
2023/24	Line Renewal	Mokai	123-02 11kV Line Renewal	269k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Line Renewal	Mokai	123-00 11kV Line Renewal	26k
2023/24	Line Renewal	Tirohanga	129-03 11kV Line Renewal	257k
2023/24	Line Renewal	Mokai	123-04 11kV Line Renewal	95k
2023/24	Line Renewal	Mokai	123-01 11kV Line Renewal	356k
2023/24	Line Renewal	Whakamaru 33	310-04 33kV Line Renewal	375k
2023/24	Regulators	Pureora Feeder	FED119 Near switch 785 just after Ranganui Road on SH 30.	96k
2024/25	Line Renewal	Whakamaru 33	310-02 33kV Line Renewal	1372k
2024/25	Regulators	Mokai Feeder	FED123 Replace Tirohanga Road regulator.	107k
2024/25	Switches	Mokai	446 Upgrade recloser to modern equivalent.	45k
2024/25	Switches	Mokai	474 Upgrade recloser to modern equivalent.	45k
2025/26	Line Renewal	Mokai	123-03 11kV Line Renewal	324k
2025/26	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Install modular substation on Sandel Road in Whakamaru.	450k
2025/26	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Replace breaker due to age, reliability and condition.	66k
2026/27	Line Renewal	Wharepapa	122-05 11kV Line Renewal	253k
2026/27	Line Renewal	Tirohanga	129-02 11kV Line Renewal	472k
2026/27	Substation and 33 kV Development	Mokai Point of Supply	ZSub3358 Increase capacity taken from Mokai Geothermal.	394k

TABLE 5-82: SUMMARY OF CAPITAL PROJECTS AND EXPENDITURE PREDICTIONS 2017/18 TO 2026/27 BY POS (WITHOUT INFLATION)

Section 6

6. Lifecycle Asset Management Planning (Maintenance and Renewal)

6.1 Description of Maintenance Planning Criteria and Assumptions

Detailed in the following sections are the key drivers for maintenance for the various asset categories. Maintenance is planned to allow the network performance to meet the targets listed in Section 4. The following maintenance planning criteria are used to ensure these performance standards are met:

Hazard Elimination and Minimisation - Ensure equipment is installed, labelled, maintained, fit for purpose and secured to eliminate or minimise hazards to staff, the public and the environment. It is assumed that stakeholders, regulators and other interested parties require equipment to be maintained to eliminate and minimise hazards. This is also required for compliance with TLC's SMS.

Reliability - Ensure equipment will reliably operate to produce the outcomes it was purchased and installed for. It is assumed stakeholders and other interested parties require equipment to be maintained in a reliable state.

Operation - Ensure equipment is maintained, used, and operated in the way that it was designed for.

This maintenance criterion assumes stakeholders will wish equipment to be used in a way that does not cause hazards, failure ahead of time or is overrated for a particular application.

Life Span - Ensure equipment is installed, operated, and maintained in a way that it reaches or exceeds its expected life span. It is assumed that equipment should be managed to ensure its expected life span is achieved.

Simplicity - Maintenance periods, policies, and criteria that are easy to understand, realistic and achievable.

Experience has shown that complex non-standard equipment or procedures leads to confusion, an increase in hazards and increased costs. It has been assumed these should be avoided.

Renewal - Equipment should be renewed when it is no longer suitable for its intended function. It is assumed that continuing with equipment that is not reliable, does not control hazards, or for which parts are no longer available, is not cost effective. Where it will not do the job it is intended for, it should be renewed. The renewal decisions should consider the criteria listed above against commercial, pragmatic, and customer considerations.

The commercial considerations include:

- Cost of maintenance versus renewal.
- Income the equipment assists in generating.

The pragmatic considerations include:

- Will it work and meet customers' expectations?
- Will it be accepted by the people who have to operate it?
- Is it reliable?
- Are any hazards associated with the equipment in line with current stakeholder expectations?
- How long will it last?
- If things change, can it be used elsewhere in the network?
- Is there good supplier support?

The customer considerations include:

- Will it work and provide a solution that allows customers to get on with their business?
- Are they prepared to fund the solution either directly or indirectly?

Overall focus is on performance to meet customers' reliability, security, and price and quality expectations in line with Section 4 indices.

6.2 Description and Identification of Routine and Preventative Maintenance Policies, Programmes or Action to be Taken for each Asset Category including Associated Expenditure Predictions

6.2.1 Summary of Maintenance Schedule

The key maintenance schedules are summarised in Table 6-1

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
All Categories	» Follow up after faults, defects and hazard reports (including "Red Tagged poles"). The resulting work will include minor maintenance through to renewal.
Overhead Lines and Cables (Excludes Ski Field Areas)	Patrols: » 18 monthly drive or foot patrol through urban areas and schools looking for potential problems including vegetation. (11 kV and LV.) » 3 yearly helicopter patrols of rural areas looking for potential problems including vegetation. (11 kV and LV.) » 12 monthly helicopter patrols of 33 kV lines looking for potential problems including vegetation. » Fault patrols of all lines after a series of auto-recloses, trippings or other reports. When these fault patrols involve a 33 kV line, a corona camera survey may be included. Most of these rural patrols are done from a helicopter. Inspections: » 15 yearly detailed inspection and renewal cycle. Emergent: » Renewals and maintenance as required to maintain supply and eliminate/minimise hazards. Emergent work often occurs as a result of following up after an event and includes a SMS hazard report.
Distribution Poles	» Maintenance or renewal as part of the line renewal programme, after faults, or emergent work.
Cables (Ski Field Areas)	Patrols: » Annual foot patrols through the low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas looking for potential problems. » 3 yearly foot patrols of cables and visual inspections of till box integrity. Inspections: » 15 yearly detailed inspections of cables and till boxes.
Vegetation	» 3 yearly patrol cycle for rural areas and 18 months for townships and schools (compliance driven). Emergent cutting to eliminate hazards or restore supply.

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
Zone Substations	» 2 monthly routine maintenance checks. » 12 monthly detailed checks. Actions include earth tests. » 2 yearly oil tests for major transformers. » 3 yearly maintenance of active oil filled circuit breakers. » 5 yearly tap changer oil and maintenance on major transformers. » 15 yearly major maintenance cycles, which include SCADA recalibration, busbar cleaning, circuit breaker timing checks, detailed inspections, painting, protection checking and extensive cleaning of the site. » Hazard elimination/minimisation projects as detailed in Section 5 (Analysis of Network Development Options) of this AMP. Emergent: » Renewals/maintenance necessary due to failures or damage. Other equipment renewals/refurbishment as detailed in Section 5 (Analysis of Network Development Options) of this AMP. » Oil refurbishment based on the results of 2 yearly oil tests.
Pole Mounted Transformers	» Renewal after failure - often caused by lightning or other damage. » Exchanged with renewed or maintained unit as part of the 15 yearly line renewal programme if the unit is in a decayed state, i.e. Rusty lid, poor paintwork etc. » Testing of earths and renewing of earthing systems as necessary. (Earth is tested as part of 15 year line inspection programme.) » Renewal or exchange with a maintained unit triggered by customer's need for more or reduced capacity.
Ground Mounted Transformers and Ground Mounted Switchgear	» 12 monthly security check and minor urgent maintenance. » 15 year major maintenance cycle. » Hazard elimination/minimisation projects as detailed in Section 5 (Analysis of Network Development Options) of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Renewals/upgrades triggered by changed customer demands.
Service Boxes	» 5 yearly inspection and renewal cycle. » Planned hazard elimination/minimisation projects as detailed in Section 5 (Analysis of Network Development Options) of this AMP. » Emergent renewals/maintenance necessary due to failures or damage (typically vehicle impacts). » Renewals/upgrades triggered by changed customer demands.
SCADA	» Maintenance repairs when the system, or parts thereof, do not operate. » Renewals of software and hardware with modern equivalents on failure. » Planned renewals to keep software and hardware up to date.
Communication	» Maintenance repairs when the system, or parts thereof, do not operate. » 12 monthly inspections of repeater sites and repairs as necessary. » Renewals of software and hardware with modern equivalents on failure. » Planned renewals to keep software and hardware up to date.

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
Load Control	» 3 monthly inspection of rotating plants and equipment room cleaning. » 2 yearly vibration analysis of rotating plants. » 12 monthly inspections of static plants and cleaning. » Planned renewals of plant as recommended by the supplier. » Hazard elimination/minimisation projects as detailed in Section 5 (Analysis of Network Development Options) of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Changes to control software triggered by changes to customer charging policies (driven by demand side management initiatives).
Three Phase Reclosers and Automated Switches	» 12 monthly inspections. » Emergent renewals/maintenance necessary due to failures or damage. » Relocations and refurbishment of equipment to fit in with the long term development plan as detailed in Section 5 (Analysis of Network Development Options) of this AMP.
Voltage Regulators	» 12 monthly inspections. » Emergent renewals/maintenance necessary due to failures or damage. » Relocations and refurbishment of equipment to fit in with the long-term development plan as detailed in Section 5 (Analysis of Network Development Options) of this AMP.
SWER Systems	» 2 yearly inspections of reclosers and sectionalisers, and testing of isolation transformer earths. » 15 yearly inspections and testing of distribution transformer earths. (Lines are patrolled 3 yearly and inspected 15 yearly as part of lines programme.) » Emergent renewals/maintenance necessary due to failure or damage - mostly earthing systems.
Fault Inspections	» 33 kV lines after recloses or trippings. » 11 kV lines after recloses or trippings. » Many fault inspections will be by helicopter as this is the most efficient way of patrolling in the rugged King Country terrain.
Other Inspections	» On-going roving. » Quality – Annual harmonic checks of key areas of the network, in particular 33 kV lines, industrial areas and a number of SWER systems. » Asset Efficiency – Annual power factor checks of key areas of the network, in particular 33 kV lines, industrial areas and adjacent to distributed generation sites.

TABLE 6-1: SUMMARY OF MAINTENANCE / RENEWAL STRATEGIES

Note: All patrols, inspections and works are recorded against the assets in the Basix asset management system.

6.2.2 Overhead Lines

Overhead lines form the highest value asset category owned and operated by TLC.

6.2.2.1 Overhead Lines: Inspection, Testing and Condition Monitoring Practices

6.2.2.1.1 Patrols – Inspection, testing and condition monitoring practices

Patrols are used to find and overcome obvious immediate asset problems and follow the schedule as listed in Table 6.1. Most of the rural patrols are done from a helicopter. Identified problems are photographed, the asset identifying numbers recorded and the location physically recorded with GPS co-ordinates. A report is completed after each patrol and data verifying that a patrol has taken place is recorded against each asset. Tools such as helicopter flight path recording via Google earth are used as additional references for the locations of defects.

The use of a corona camera has been successful in finding damaged insulators on 33 kV lines when carrying out helicopter patrols. Most of these faults are caused by insulator flashover from fertiliser build-up. In the extreme they escalate to crossarm failure. The corona camera has not proved successful for finding problems on 11 kV lines.

Helicopter patrols are cost-effective and provide a quick way to cover long lengths of lines in rugged country. The average cost is $30 to $50 per km. They are also a good way of ensuring customers know TLC is concerned about their supply, with most rural customers appreciative of a low level helicopter check after a series of auto recloses. The biggest negative to helicopter patrols is stock disturbance, particularly when intensive break feeding of cattle is taking place. Staff are stock conscious and keep a watch ahead of flight paths for potential stock and other issues. High level fly overs are often undertaken to check for stock before low level inspections. Where possible we advise farmers of patrols ahead of time.

Helicopter patrols are not possible in urban areas and around places such as schools where more detailed shorter cycle patrols are required. Urban and school areas are patrolled from the ground on an 18 month rotation to identify problems and potential hazards.

Other special one-off patrols are also completed from time to time. For example, if a 33 kV line is to be used as an alternative supply while Transpower has a grid exit point out of service for maintenance, the line will be patrolled beforehand. Key lines are often patrolled preceding special events such as long holiday weekends.

Patrols may take place after a series of auto recloses to try and identify the cause of the trippings. Patrols are also completed after customers express concern or report some type of problem with equipment.

6.2.2.1.2 Inspections - Inspection, testing and condition monitoring practices

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance and renewal programmes.

The inspection assessment includes:

- Travelling to each pole and assessing the condition of all hardware, cross-arms, conductors etc.
- Testing the pole - if practical and access is possible - with a mechanical strength tester.
- Photographing the pole and associated hardware.
- Plotting the position by GPS.
- Measuring span lengths.
- Checking vegetation and recording any other issues associated with line security.
- Visually checking the integrity of the transformer and equipment earthing.
- Visually checking all earthing at transformer and equipment sites. Testing is also completed.
- Visually checking all HV fuses and air break switches. This includes visually checking and testing the earthing system.
- Checking all switch and fuse labelling and re-labelling if they are not readable.

- Checking pole labelling and re-labelling with new asset numbers as required.
- Checking all transformers and other equipment labelling.
- Completing data sheets.
- Establishing walking access to pole sites. This may involve cutting a track through bush, scrub etc.
- Initial renewal specifications, and design when renewal is being proposed by the inspector. The inspectors' assessment and specified renewal requirements are desk top checked and calculations are completed.
- Site access details are recorded for renewal recommendations.
- Recording and specifying any minor maintenance needs.

6.2.2.2 Overhead Lines: Processes for ensuring overhead line defects identified by the Inspection and Condition monitoring programmes are rectified

6.2.2.2.1 Patrols – Ensuring defects are rectified

Data from the patrols are returned to the asset and engineering management section for processing. Data and defect reports are reconciled to asset database and the types of assets. The locations of assets are verified along with any other information stored against the asset. Vegetation data are separated out and forwarded to vegetation control and follows the process detailed in later sections.

Repairs and renewal instructions from the patrollers are then checked and instructions to field staff are prepared. For larger problems, detailed designs may be included and financial approval from Directors may have to be secured. Once the appropriate specifications, designs and approvals are obtained, works orders are issued to the internal Service Provider. The Service Provider then schedules and completes the work. Once notification is received that work has been completed, it may be audited (particularly larger jobs) by a lines inspector/designer before final payment is approved. Asset records are updated as part of the final settlement process. The auditing ensures work is completed to the specifications and that all assets are correctly labelled.

6.2.2.2.2 Inspections – Ensuring defects are rectified

The following processes are used for rectifying defects and ensuring data are correct after detailed inspections:

- Appropriately qualified and experienced staff conduct the inspections.
- Inspections are reconciled against the asset data records.
- Gathered data and photographs are loaded into databases.
- Strength calculations on selected assets are carried out using a line design package.
- Field inspector's designs are reviewed and modified as necessary.
- Co-ordinate renewals and maintenance with other works.
- Investigate the outages needed to do the work and the implications of the outages.
- Put together work packages and specifications including specifying requirements to eliminate or minimise hazards.
- Notify landowners and discuss proposals.
- Prepare, obtain and check cost estimates. This includes reconciling industry current cost survey data.
- Issue work to contractors.
- Receive and process applications from contractors to work on network. Police contractors to ensure they eliminate/minimise hazards, are approved to work on network and have hazard control programmes in place.
- Receive notification from contractors that works are complete and audit work for compliance with the specifications.

- Review private line connections and ensure customers understand their liabilities under the Electricity Act and its regulations. In extreme cases for private lines that pose a significant hazard, details are forwarded to Energy Safety for enforcement. (The Electricity (Safety) Regulations 2010 impose significant liability for private lines on the line owners. At this time the various government bodies do not appear to have co-ordinated their activities in this area, nor understood the implications of the liabilities the Regulations place on the rural communities.)
- Re-audit and where required issue further network instructions.
- Accept invoices and reconcile to original estimates.
- Carry out line owner follow-ups.
- Settle any outstanding landowner or line owner issues.
- Ensure all as built data and databases are updated.

6.2.2.3 Overhead Lines: Systemic Problems and Solutions

Table 6-2 summarises the systemic problems associated with lines and the steps taken to address these. Some of these issues were discussed in Section 3.3.

OVERHEAD LINE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Insulator failures advanced by fertiliser build up and magpies.	» Taller insulators with longer creepage distances.
Air Break Switch failures due to poor manufacturing and connections.	» Greater quality focus on connections and use of proven switch types.
Tree and other environmental issues such as flooding and slips.	» Tree programme in place. » Equipment located away from flood prone land. » Slips continually watched during helicopter patrols and inspections. Poles moved to less hazardous locations.
Wire clashing.	» Greater focus on line design, fault current control designs and wire spacing/tension.
Insulator wire ties breaking due to vibration and loading.	» Greater focus on quality of hardware. » Larger size binder wire used. » Galvanised steel pre-form wire ties that tend to corrode are not used.
Connection failure due to dissimilar metal reactions.	» Greater focus on the quality of connectors and types used. They must be straight forward and simple to apply, yet robust and able to handle dissimilar metals.
Drop out fuse failures.	» Careful component selection. » Attention to corrosion, connections and clearances for hazard elimination/minimisation.
Pole cross-arms and other hardware problems.	» Focus on component workmanship quality and design, in particular making sure correct pole and component strengths are used. » Planned renewal programme and making sure reported problems are followed up. This is critical for improving reliability, SMS, security and hazard control.
Private responsibility overhead lines interfering and causing problems with TLC assets.	» Increased fusing of private lines. » Increase publicity to owners to improve their awareness and understanding of the complex issues for compliance with Electricity Regulations. » Better data systems including more detail on ownership and responsibility for lines.

TABLE 6-2 SYSTEMIC PROBLEMS ASSOCIATED WITH LINES

6.2.3 Cable (Ski Field Areas): Inspection, Testing and Condition Monitoring Practices

6.2.3.1 Patrols – Inspection, testing and condition monitoring practices

Foot patrols are used to find and overcome obvious immediate asset problems. Identified problems are photographed, the asset identifying numbers recorded and the location physically recorded with GPS co-ordinates. A report is completed after each patrol and data verifying that a patrol has taken place is recorded against each asset.

Annual Foot patrols are conducted in low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas. A foot patrol of the whole cable length is done over 3 years (the cable length is split into 3 sections and each section is done once in the 3 years). Patrols may take place after a series of auto recloses to try and identify the cause of the trippings.

6.2.3.2 Inspections - Inspection, testing and condition monitoring practices

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance. Cables are maintained on a time based programme.

Time based inspection and maintenance programmes include:

- Three yearly cable and till box integrity inspection
- 15 yearly detailed cable termination and till box termination inspections as well as earth testing and insulation resistance testing.

6.2.4 Vegetation

6.2.4.1 Vegetation: Reliability and Compliance of Vegetation Control Programmes

The 2003 Reliability Report identified vegetation maintenance as an important component in improving network reliability. Analysis found that a large number of the faults had their root causes associated with vegetation. The Electricity (Hazards from Trees) Regulations 2003 were gazetted in December 2003 and focused on controlling hazards after the electrocution of a child in Auckland.

Analysis of tree data, collected since 2003, shows that complying with the regulations and thereby reducing hazards also increases costs. This cost increase is due to the administration/supervision needed to manage the processes as specified by the regulations and TLC's responsibilities when tree owners do not cut trees. The cut distances stipulated in these regulations focus on ensuring people cannot climb a tree and touch energised conductors. These distances will help reliability, but do not ensure that clearances are great enough to stop trees falling through lines.

Overall the implementation of vegetation and compliance strategies has meant that landowners have become more aware of their responsibilities. Generally most co-operate and allow trees to be cut.

6.2.4.2 Vegetation: Inspection, Testing and Condition Monitoring Practices

6.2.4.2.1 Planned – Inspection, testing and condition monitoring practices

A review of TLC's tree strategy took place during late 2006. The strategy adopted as a result of the 2006 review was to focus more on maintaining the areas where cutting had taken place in the 4 years previous and moving out into uncut areas in response to outage and known problem areas. Since this time the three yearly patrols have covered the more remote uncut areas and most of these have now been addressed. At this point in time the clearances on the outlying lines are not as great as the clearances along more important lines; however, distances are increasing with each 3 yearly cycle. Vegetation patrols are included in the line patrols outlined in the preceding sections.

Costs associated with vegetation control are included in the maintenance expenditure projections. The areas patrolled each year are identified by feeders and asset groups. The workflow includes the following key activities:

- Split the network into three 30% groupings.
- Fly one group in a particular year.
- GPS trees and other line problems observed.
- Complete a written report giving specifications and prepare instructions for each work site.
- Record work completed in the asset database.

6.2.4.2.2 Unplanned – Inspection, testing and condition monitoring practices

Emergent notifications of tree problems are received from customers, staff and other sources. Records are taken of these notifications and the issues are investigated by TLC's line inspectors. Customer liaison, work specifications and instructions are undertaken for each site.

6.2.4.3 Vegetation: Processes for ensuring defects identified by Inspection and Condition monitoring programmes are rectified

Once tree inspection personnel have identified, specified and detailed requirements, further processing is completed by administrators.

This processing includes:

- Laying out on maps the locations of vegetation infringements.
- Reconciling locations and instructions to previous cut data.
- Notifying and discussing issues via mail or directly with landowners. The approach taken is dependent on the issue, previous history and local knowledge.
- Engaging tree contractors to carry out work.
- Receiving cut data and invoices from tree contractors.
- Storing all cut data including costs, landowner agreement details etc. in the Basix database.
- Allocating, scheduling and co-ordinating personnel for auditing of completed work and any necessary landowner follow up.

6.2.4.4 Vegetation: Systemic Problems and Solutions

Table 6-3 summarises the systemic problems and solutions associated with vegetation and the steps taken to address these.

VEGETATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Landowners planting under lines.	» 3 yearly patrols following up on new plantings.
Trees that breach the fall distance.	» Charging landowners for problems caused by trees that breach the fall distance if the tree does fall through lines.
Landowners not complying with Tree Regulations.	» Strict follow up on notices. » Account follow up on any invoiced charges.
Legacy issues.	» Issues are addressed one at a time when problems occur. They are mostly associated with plantation owners and their desire to maximise forest production.
Forest fires started by trees falling through lines.	» The Rural Fire Act has been poorly written, leaving network companies liable for damage caused by trees, no matter how good their tree programmes are. Insurance is the only solution to potential liabilities.

TABLE 6-3 SYSTEMIC PROBLEM AND SOLUTIONS ASSOCIATED WITH VEGETATION

6.2.5 Zone Substations

6.2.5.1 Zone Substations: Inspection, Testing and Condition Monitoring Practices

Zone substations and voltage control equipment are maintained on both a time and a condition based programme.

Time-based inspection and maintenance programmes include:

- Inspections every two months to ensure site security and identify potential hazards. General operation is checked and minor maintenance issues addressed such as batteries, servicing and weed spraying.
- Annual substation earth tests.
- Two yearly oil and other testing as appropriate for the site: i.e. corona, partial discharge and thermo vision. Major equipment oil tests are conducted to ensure equipment, particularly transformers, are within operating specifications.

A fifteen year major maintenance cycle where equipment is extensively maintained and tested. The fifteen year major maintenance cycle was selected based on:

- The typical period a good paint job lasts, and an appropriate period for a repaint.
- The typical maximum period that technical equipment can be expected to operate reliably before extensive maintenance/renewal and testing. The scope of this work varies from site to site but typically includes protection testing, circuit breaker timing tests, SCADA calibration checks, busbar cleaning etc.
- Three yearly oil changes in active Oil Circuit Breakers.
- Five yearly tap changer oil changes.

The condition-based programmes include:

- Maintenance of equipment after faults.
- Maintenance of transformers after oil analysis.
- Renewal of faulty equipment.
- Maintenance or renewal after testing.

Table 6-4 summaries the inspection regime for substations.

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES			
Asset Inspection	**Routine Inspection Frequency Period**	**Scheduled Maintenance Frequency Period**	**Operations**
1 Substation buildings and grounds	2 Monthly	-	
2 Power transformers and voltage regulating transformers:-			
- Oil sample and Dissolved Gas Analysis	-	2 Yearly	
- Oil levels	2 Monthly	-	
- Silica gel breather	2 Monthly	Annually	
- Earth connections	-	Annually	
- Tank	2 Monthly	15 Yearly	
- Radiators	2 Monthly	15 Yearly	
- Tap changer mechanism	2 Monthly	5 Yearly	
- Tap changer oil & diverter switches		5 Yearly	
- ABB & Cooper VR 32's	2 Monthly	15 Yearly	50,000
- Buchholz	2 Monthly	5 Yearly	
- Insulation resistance	-	5 Yearly	

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES				
	Asset Inspection	**Routine Inspection Frequency Period**	**Scheduled Maintenance Frequency Period**	**Operations**
3	Outdoor Busbars, Airbreak switches & structure supports	2 Monthly	15 Yearly	
4	Outdoors VTs and CTs	2 Monthly	15 Yearly	
5	Lightning arrestors	2 Monthly	15 Yearly	
6	33kV OCBs - McGraw Edison - Vacuum Break - Oil break - Scarpa Magnino - Generator OCBs - Taharoa Substation - Others	 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly	 15 Yearly 3 Yearly 3 Yearly 3 Yearly 3 Yearly 15 Yearly	
7	11kV Metal Clad OCBs - Generator OCBs (oil break) - Other oil break - Vacuum break	 2 Monthly 2 Monthly 2 Monthly	 3 Yearly or 3 Yearly or 15 yearly	 Post fault 60
8	11kV Fuse Switches	2 Monthly	15 Yearly	
9	11kV Pole Mounted OCBs - Oil break - Vacuum break	 2 Monthly 2 Monthly	 3 Yearly or 15 Yearly	 60
10	11kV Pad Mounted Transformers	2 Monthly	15 Yearly	
11	11kV Switchboard and Internal Busbars	2 Monthly	15 Yearly	
12	Substation Protection Relays	2 Monthly	15 Yearly	
13	Load Control Equipment	2 Monthly	Annually	
14	Battery Banks and Charges	2 Monthly	3 Yearly	
15	Substation phones and radios	2 Monthly	15 Yearly	
16	R.T.U's and Dehumidifiers	2 Monthly	15 Yearly	

TABLE 6-4 : ZONE SUBSUBSTATION EQUIPMENT AND MAINTENANCE REGIME

In addition to these practices, various components and architecture associated with zone substations are included in the long-term renewal and development programmes outlined in Section 5 (Analysis of Network Development Options) of this AMP. This renewal and development work is implemented in addition to the above programmes.

Many of TLC's zone substation components are old and, when they fail, repairing existing equipment is not an option due to parts availability. In these situations components are renewed with modern equivalents.

6.2.5.2 Zone Substations: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Zone substation renewal and maintenance workflows will follow several paths. In summary these include:

Two-Monthly Inspections: Data records are completed and returned after work has been done. These are reviewed by engineering staff and reports are entered into databases. Works are specified and orders are raised for non-conforming issues. Follow up audits are completed to ensure work is done to specifications.

Annual Substation Inspections and Tests: Results are checked and when tests are outside codes, regulations or good industry practices, designs are completed and works orders are issued. Follow up tests are completed and works are audited to ensure work is done to specifications.

2 and 3 yearly Inspection and Testing: Works orders are raised every two years for full Dissolved Gas Analysis testing of oil in main tanks of 33/11kV transformers. The results are reviewed by a consultant and updated information used for the oil maintenance programme and long term asset condition. Works orders are raised for corona, partial discharge and thermo vision testing relevant to a particular site to follow up any outstanding issues. Where tests indicate oil maintenance is needed, specifications are prepared and works orders are issued. Follow up tests are done as necessary after work as part of the auditing process. All results and actions are recorded against the asset.

5 and 15 year Maintenance: A task list is put together that is additional to planned renewal and minor maintenance. Work may include any catch-up needs and other items such as painting, wooden arm replacement, corroded steel work, protection tests, SCADA calibration checks etc. The 2 monthly inspection data and site condition information is the main input into the specifications associated with this work.

Schedules for each substation may differ but they generally follow the list in table 6-1 and 6-4.

Maintenance of Equipment after Faults: The Engineering staff specifies and allocates the work to contractors. The Engineering staff review and evaluate the options. Usually the lowest cost option is selected, which often involves renewal of equipment components with modern equivalents. In all cases specifications are prepared and works orders are issued after quotes are obtained.

6.2.5.3 Zone Substations: Systemic problems and solutions

Table 6-5 summarises the systemic problems associated with zone substations and the steps taken to address these. Many of these issues were discussed in more detail in Section 3.3.

ZONE SUBSTATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solutions**
Voltage control and protection systems	» Repair or, if obsolete and parts not available, renew equipment.
Transformer failure after passage of fault current	» Limit fault current by design. » Dry and tighten transformer cores when oil test indicates high moisture content in insulation.
Lightning damage	» Design for lightning protection.
Switchgear failure	» Repair or, if obsolete and parts not available, renew.
Insecure fences	» Repair or renew.
Transformers ageing	» Regular oil tests. » Oil or transformer refurbishment. » Contingencies in case of failure.
Discharging switchgear and cables	» Clean, re-terminate or replace faulty components.

TABLE 6-5: SYSTEMIC PROBLEMS ASSOCIATED WITH ZONE SUBSTATIONS

6.2.6 Distribution Pole Mounted Transformers

6.2.6.1 Distribution Pole Mounted Transformers: Inspection, Testing and Condition Monitoring Practices

Pole mounted transformers are maintained when:

- The 15 yearly cycle line renewal/maintenance programme inspection and test process finds aged or poor condition transformers.
- After site visits, due to faults or other reasons, transformers are found to be in poor condition.
- Customers require increased or reduced transformer sizes.
- When hazard elimination/minimisation projects are completed at a site and the transformer is exchanged. Often a different transformer configuration is needed when a hazard elimination/minimisation project is completed.
- TLC receives reports or information indicating that the earthing system has been compromised.

6.2.6.2 Distribution Pole Mounted Transformers: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Transformers, when returned from the field, are sorted into three categories.

These are:

- Return to field without any work.
- Refurbish.
- Write off.

The decision as to which category transformers go into is controlled by the Operations or Technical Support Engineer. The decision is made on a number of criteria:

- The cost of refurbishment versus repair.
- Bushing layout and hazard control issues likely at future sites the transformer may be located.

Work orders are raised for transformer refurbishment and the costs are placed against the transformer asset. Once completed and ready for service, they go back into the available stock. The Basix asset management system is the main tool used to track these costs and transformer movements.

Maintenance of pole hanging transformers typically involves painting, oil filtering and bushing replacement if damaged. Pole hanging transformers with internal winding faults are usually written off.

6.2.6.3 Distribution Pole Mounted Transformers: Systemic Problems and Solutions

Lightning damage, age and tank rust are the typical systemic problems with distribution transformers. The solution is either to refurbish or renew. Lightning arrestors and over-current protection fuses are fitted to all transformers. In recent times problems have been experienced with earthing systems being stolen for copper value. There are no solutions at present to eliminate this problem.

6.2.7 Ground Mounted Transformers

6.2.7.1 Ground Mounted Transformers: Inspection, Testing and Condition Monitoring Practices

Ground mounted transformers are inspected 5 yearly.

These checks include:

- Labelling and danger signs.
- Inspection of the physical integrity of the site including equipment, equipment numbering, safety labelling and earthing.
- Recording and resetting Maximum Demand Indicators.
- Locks, labels and any switchgear locks, fuses, operating equipment etc.
- Minor maintenance including painting over any superficial graffiti.
- Visual check of any switchgear attached to the site.
- General spot heat check of equipment.
- Data reconciled for site including photographs.

This annual inspection data feeds into a fifteen-year major maintenance programme. The major maintenance programme is also linked to other programmes such as line and switchgear renewals. Sites have been assessed and prioritised based on the annual data collected.

Major maintenance includes:

- Painting and site security (additional locks).
- Insulating exposed terminals.
- Internal cleaning and part replacement.
- Renewal is generally triggered by condition and the need to control hazards.

6.2.7.2 Ground Mounted Transformers: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Defects found as part of the 5 yearly checking process have work specifications prepared and orders are issued. Completed works are monitored and reconciled to works orders.

The major renewal and major maintenance work coming out of 5 yearly inspections are prioritised and detailed in future plans by site. In the year preceding the planned work, the network engineers work through these lists and prepare detailed specifications. These are forwarded to contractors for pricing generally before the programmed year for the works.

During the planned year, works orders are issued to contractors. Once work is completed, auditing takes place before invoices are paid. At the completion of work, data and plans are updated.

6.2.7.3 Ground Mounted Transformers: Systemic Problems and Solutions

6.2.7.3.1 Hazard Control – Special Maintenance

All ground mount transformer sites have been inspected and assessed for hazards. Whilst some will be replaced in the renewal work programme, others will have maintenance completed to allow the renewal programme to be cycled. Systemic problems and solutions are summarised in Table 6-6.

GROUND MOUNTED TRANSFORMER SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Graffiti	» Repaint
Rust and decay	» Treat and repaint » Renew if severe
Labels missing or faded	» Relabelled
Locks broken or seized up	» Replace or repair
Exposed bushings	» Tape or, if not practical, renew
Oil leaks	» Minor - on site repairs » Major – exchange/renew
Overheated connections	» Renew connections and associated equipment (circuit breakers, fuses etc.)
Damaged earthing	» Replace or repair earthing
Exposed LV	» Cover or renew

TABLE 6-6 : GROUND MOUNTED TRANSFORMERS: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.8 Service Boxes

6.2.8.1 Service Boxes: Inspection, Testing and Condition Monitoring Practices

Service boxes are being inspected on a five-yearly rotation.

This inspection includes:

- Security check.
- Location details (GPS, and placement on GIS maps).
- Number check including renumbering if the number has come off.
- Damage check.
- Integrity check.
- Reconciling type and approximate age to asset records.
- Minor repairs such as replacing screws or locks.
- Identifying access, fences and vegetation issues.
- Fitting/refitting of hazard and identification labels.

Service boxes are often found in a poor state due to vehicle damage. If the inspection reveals the need for further work then these requirements are factored into future renewal programmes.

The maintenance data collected is reviewed and a renewal programme is formulated based on this. The renewal programme is detailed further in the constraints and renewal section of the AMP. In summary, this focuses on renewing damaged (and fibreglass type) boxes that have become brittle due to age. The maintenance programme focuses on more minor repairs including making sure boxes are numbered, hazard labelled and secured. There are a number of boxes with un-earthed metal fronts/lids. These are being replaced with plastic fronts/lids as part of this programme.

6.2.8.2 Service Boxes: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Defects found as part of the five-yearly inspection process have work specifications prepared and orders are issued. Completed jobs are monitored and reconciled to works orders. Emergent defects are reported to the asset management administrators, work specifications are prepared and orders are issued. Completed jobs are monitored and reconciled to works orders.

All service boxes are numbered and have details recorded in the asset database. The location details are added to the mapping database.

6.2.8.3 Service Boxes: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6-7.

SERVICE BOX SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Vehicle damage.	» Straighten and re-secure or replace
Decay due to age (especially fibreglass units).	» Renew
Unearthed metal covers.	» Replace covers with plastic or renew whole unit
Cover screws stripped or missing.	» Replace screws, install new inserts or renew box as necessary to secure the unit.

TABLE 6-7: SERVICE BOXES: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.9 SCADA

6.2.9.1 SCADA: Inspection, Testing and Condition Monitoring Practices

SCADA equipment is maintained to ensure it is always in good working condition. This maintenance is completed on a combination of time and condition-based approaches.

Annual work includes installing the latest software, checking calibration, battery testing, replacement and other tuning. The condition-based work largely involves carrying out repairs after equipment has failed or the renewal of aged, obsolete equipment.

6.2.9.2 SCADA: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor SCADA operations and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

Checks of field equipment are completed as part of zone substation, recloser and regulator inspections. Batteries and the like are checked and, if outside specifications, are renewed at these times.

6.2.9.3 SCADA: Systemic Problems and Solutions

Over the last few years, the most common systemic problems with SCADA have been lightning and fault current generated surges affecting electronic equipment. The solutions to these problems include a combination of bonding and earthing.

From time to time there are other minor problems associated with complex electronic equipment. The renewal programme discussed in other sections focuses on keeping equipment up to date and in good condition.

6.2.10 Radio Repeater Sites

6.2.10.1 Radio Repeater Sites: Inspection, Testing and Condition Monitoring Practices

Radio voice and data communication equipment is critical to the safe operation of the network. Time-based work includes annual visits to repeater sites and checking of equipment at these sites. These checks include:

- Aerial and feeder cable inspections.
- Connector inspections.
- Building checks and minor maintenance.
- Battery and charger checks and servicing.
- Alignment and level checks including bandwidth and carrier frequencies.
- Other general minor works and adjustments.
- "Gain" and other radio tests.

Condition-based work includes repairs after failure or renewal of aged, obsolete equipment.

6.2.10.2 Radio Repeater Sites: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor radio operation and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

The renewal programme discussed in other sections focuses on keeping equipment up to date and in good condition.

6.2.10.3 Radio Repeater Sites: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6-8.

RADIO REPEATER SITE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Lightning damage.	» Replace damaged equipment. » Ensure adequate protection devices installed.
Flat batteries.	» Ensure annual servicing and battery replacements are completed.
Radio equipment out of specification.	» Retune equipment. » Retain a strategy of renewing equipment to keep up to date.

TABLE 6-8: RADIO REPEATER SITES: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.11 Load Control

6.2.11.1 Load Control: Inspection, Testing and Condition Monitoring Practices

6.2.11.1.1 Rotating plant

Rotating plants are visited every 3 months and the following checks are completed:

- Operation.
- Building clean.
- Generator brush gear.
- Contactors.
- Visual checks of other components.

Other general servicing and minor adjustments are completed in addition to the above. Every 2 years vibration checks of motor generators are carried out to ensure bearings have not worn excessively and equipment is balanced.

6.2.11.1.2 Static Plants

An annual inspection and operational check is made of static plants. During this visit inductor and capacitor enclosures are also weed sprayed and cleaned as necessary. The plants are retuned, and inductance and capacitance values checked when injection power levels are out of specification.

6.2.11.2 Load Control: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor load control operation and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.11.3 Load Control: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6-9.

LOAD CONTROL SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
No signal getting to plant.	» Repair communication or SCADA system.
Plant power electronics or controller failure.	» Repair using specialist technicians.
Electro Mechanical Plant generators not operating.	» Vibration and regular checking of brushes etc.
Electro Mechanical Plant contactors failing.	» Inspection and repairs of contacts.

TABLE 6-9: LOAD CONTROL: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.12 Three Phase Reclosers and Automated Switches

6.2.12.1 Three Phase Reclosers and Automated Switches: Inspection, Testing and Condition Monitoring Practices

An annual inspection of 3-phase line reclosers and automated switches is carried out.

The inspection involves:

- Checking site and equipment integrity.
- Checking numbering and labelling. This includes renewing labels if they are incorrect or not readable.
- Replacing gel cell batteries - typically on every third visit.
- Checking charging systems.
- Checking/testing earthing.
- Checking SCADA and radio systems.
- For electronic units, downloading all memory buffers and settings.
- Reconciling settings to records including load flow and fault study models.
- For manual units, recording operations counters.
- Where recloser bypass switches are fitted, operate these to allow the switch remote and local operating functions to be tested.

6.2.12.2 Three Phase Reclosers and Automated Switches: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The control room and engineering staff monitor line recloser and automated switch operation. When problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.12.3 Three Phase Reclosers and Automated Switches: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6-10.

THREE PHASE RECLOSERS AND AUTOMATED SWITCHES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Faulty or flat batteries.	» Replace after 3 years.
Software and programming errors affecting settings.	» Download and reconcile annually » Re-adjust and monitor.
Hardware, connections and earthing.	» Visually check annually. » Carry out repairs as necessary.
Operating outside settings.	» Service, retest and tune as necessary. » Run network analysis to find a solution when necessary.

TABLE 6-10: SYSTEMIC PROBLEMS AND SOLUTIONS FOR THREE PHASE RECLOSERS AND AUTOMATED SWITCHES

6.2.13 Voltage Regulators

6.2.13.1 Voltage Regulators: Inspection, Testing and Condition Monitoring Practices

Voltage regulators are inspected annually. The inspection includes:

- Checking site and equipment integrity.
- Checking numbering and labelling.
- Replacing any control equipment batteries (typically every third visit).
- Checking charging systems (remote control and SCADA).
- Downloading all memory buffers and settings.
- Checking numbers of operations and range.
- Reconciling settings and operations to records and network analysis software.
- Check/testing earthing.
- Checking operation.

6.2.13.2 Voltage Regulators: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The control room and engineering staff monitor voltage regulator operation and when problems are found, ensure specifications and work orders for repairs are issued. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.13.3 Voltage Regulators: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6-11.

VOLTAGE REGULATORS: SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Faulty or flat batteries in Control equipment.	» Replace at manufacturer's recommended intervals.
Software and programming errors affecting settings.	» Download and reconcile annually. » Readjust and monitor.
Hardware connections and earthing.	» Visually check annually. » Carry out repairs as necessary.
Operating outside settings.	» Service, retest and tune as necessary. » Run network analysis to find a solution when necessary.

TABLE 6-11: SYSTEMIC PROBLEMS AND SOLUTIONS FOR VOLTAGE REGULATORS

6.2.14 Single Wire Earth Return Isolating Transformer Structures

6.2.14.1 Single Wire Earth Return (SWER) System Isolating Structures: Inspection, Testing and Condition Monitoring Practices

TLC operates just over 60 SWER systems. A vital component of the SWER system is the isolation transformer and associated earthing system. Isolation transformer sites are inspected two yearly and the following inspections/tests are completed:

- The earthing system is visually inspected and electrically tested.
- Operation counter readings are recorded at recloser and system sectionaliser sites. These are reconciled to previous readings.
- Maximum Demand Indicators (if fitted) are read and reset.
- Labelling is checked and where necessary labels are renewed.
- System configuration is checked, i.e. by-pass switches, links etc. and reconciled with control room records.
- Site security and integrity is checked.

The distribution transformer earths downstream of the isolation transformer are inspected and tested on a 15 year cycle.

6.2.14.2 Single Wire Earth Return System Isolating Structures: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The Lines Inspectors complete testing and forward results to asset management staff. These results are analysed and specifications are prepared for improvements to sites with earth mats that have resistance values that are above the TLC's standard or/and outside regulatory values. Network analysis design software is used to assist with improving the earth mat design. Improvement work packages are issued to contractors. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against sites and annual plans.

6.2.14.3 Single Wire Earth Return System Isolating Structures: Systemic Problems and Solutions

The systemic problems with this equipment, and the solutions, are summarised in Table 6-12.

SINGLE WIRE EARTH RETURN SYSTEM ISOLATING STRUCTURES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Earth potential rises around earth mat.	» Test and maintain
Structures have hazards that need elimination/minimising (working clearances, ground clearances etc.)	» Include in a Renewal Programme

TABLE 6-12: SYSTEMIC PROBLEMS AND SOLUTIONS FOR ISOLATING TRANSFORMER STRUCTURES ON SWER SYSTEMS

6.2.15 SWER (Single Wire Earth Return) Distribution Transformers Structures

6.2.15.1 SWER Distribution Structures: Inspection, Testing and Condition Monitoring Practices

For SWER distribution systems to work effectively, low resistance earth systems must be installed and maintained. The earthing systems on distribution SWER systems were all reference tested during the 2006/07 and 2007/08 years. A number of improvements were completed. Going forward, a 15 year cyclic testing programme has been introduced.

The objective of the programme is to ensure the hazards associated with SWER systems are minimised and, specifically, that the earth potential rises around earth mats are within acceptable limits. The maintenance earth inspections also focus on identifying sites where there is bonding between HV and LV earthing systems.

6.2.15.2 SWER Distribution Structures: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The Lines Inspectors complete testing and forward results to asset management administration staff. The results are analysed and specifications are prepared for improvements to sites with earth mats that have high values. The network analysis software is used to assist with site improvement design.

Improvement work packages are issued to contractors. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against sites and annual plans.

6.2.15.3 SWER Distribution Structures: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6-13.

SINGLE WIRE EARTH RETURN SYSTEM DISTRIBUTION STRUCTURES: SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Steps to Address**
Broken HV earth wire when bonding is in place to LV MEN earthing system. This results in 11kV being available at installation switchboards if the main earthing conductor is open circuited.	» Locate installations by inspection and testing. » Install separate earthing systems.
High impedance earth connections.	» Earth potential rises around occupied dwellings especially under fault conditions overcome by improving earthing systems. » Design and specify new systems using tools such as the network analysis programme.
Bonded HV and LV MEN earths (MEN then becomes an 11 kV current path).	» Install separate earthing systems.

TABLE 6-13: SYSTEMIC PROBLEMS AND SOLUTIONS FOR DISTRIBUTION TRANSFORMERS ON SWER SYSTEMS

6.2.16 Other System Inspections

6.2.16.1 Other System Inspections: Inspection, Testing and Condition Monitoring Practices

All asset and engineering staff visually check assets on their travels to ensure equipment integrity. Specific items of importance include:

- Equipment labelling and integrity.
- Locking of equipment.
- Obvious defects.
- Close excavations, cranes etc.

6.2.16.2 Other System Inspections: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

It is the responsibility of engineering and asset management staff to follow through and ensure the defects observed are rectified. They have to select the correct process. Hazard issues such as cranes and excavators that are being operated close to network assets are followed up by the Controller and Inspection and Vegetation Controller.

6.2.16.3 Other System Inspections: Systemic Problems and Solutions

Customers and contractors are often reluctant to ensure machinery operating close to lines complies with regulations. A discussion pointing out the hazards is normally sufficient to overcome the issue.

6.2.17 Power Quality

6.2.17.1 Power Quality: Inspection, testing and condition monitoring

Voltage readings are taken from time to time - either initiated by customer complaints or engineering analysis. Harmonic levels and loadings are checked at the same time. Spot checks are completed annually at key locations throughout the network to monitor total harmonic distortion. These checks are made at the same locations each year.

Voltage, current and other data are logged at remotely controlled equipment and substations. In a number of cases distributed generation has been found to have adverse effects on local voltage. In these cases TLC has requested modifications to generator controllers. The logged data are used for various activities including:

- System planning and analysis.
- Fault finding.
- On-going power quality monitoring.
- Reconciling to network analysis programme and performance targets.
- Reconciling loads to billable demand based charges from the various parts of the network.

6.2.17.2 Power Quality Monitoring: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programme are Rectified

Voltage issues are followed up by either short term adjustment of transformer taps, regulators or tap changers. Where the problem is found to be in a customer installation or works, this information is passed on to the customer. Network modelling is used to identify the issues associated with longer term problems. Solutions are developed and included in the AMP.

The network harmonic levels are being carefully monitored to understand the effect of the increasing number of appliances and other equipment that include power electronics. Harmonic measurements are showing high levels of total harmonic distortion on parts of the TLC network, particularly SWER systems, lightly loaded long lines and around industrial installations.

TLC is rectifying this problem by being particularly sensitive to power electronics associated with new connections including distributed generation and the specifications in the connection codes and standards. In the longer term it may be necessary to add filters to some SWER systems.

6.2.17.3 Power Quality Monitoring: Systemic Problems and Solution

The systemic problems with quality monitoring and the solutions are summarised in Table 6-14.

POWER QUALITY MONITORING: SYSTEMIC PROBLEMS AND SOLUTION	
Systemic Problem	**Steps to Address**
Incorrect readings due to instrument calibration.	» Ensure good quality instruments are used that have calibrations checked regularly. » Ensure substation and equipment maintenance programmes routinely check transducer calibrations and recording equipment are accurate.
Issues that can be rectified by short term network adjustment and tuning.	» Specify instructions and issue work orders to field staff. » Where appropriate follow up and audit.
Issues that cannot be rectified by short term network adjustment and tuning.	» Include in longer term planning, development and renewal programmes (e.g. filters and blocking chokes).

TABLE 6-14: SYSTEMIC PROBLEMS AND SOLUTIONS IN POWER QUALITY MONITORING

6.2.18 Asset Efficiency

6.2.18.1 Asset Efficiency: Inspection, Testing and Condition Monitoring Practices

6.2.18.1.1 Power factor and network losses: Inspection, testing and condition monitoring practices

Spot checks are completed annually at key locations throughout the network to monitor power factor in the distribution and sub-transmission system. Particular attention is paid to 33kV feeders, industrial areas and distributed generation sites.

The national data set is obtained annually from the Electricity Commission and the grid exit power factors are monitored. Data are also downloaded from other equipment that is capable of monitoring power factors. All power factor data are reconciled to current system network analysis data so that modelling is as close as possible to actual network active and reactive power flows. Network loss calculations are completed annually to benchmark technical losses. Billed energy data are obtained from the Reconciliation manager and reconciled to calculated technical losses and the amount of energy coming into the network. (Data from the Reconciliation Manager also include distributed generation injection.) Network loss calculations are completed annually to benchmark technical losses.

6.2.18.1.2 Network constraints: Inspections, testing and condition monitoring practices

Network models are run annually as part of the AMP process to determine network constraints. Peak loading models of each grid exit are run based on the recorded previous period peak loading conditions. The constraint areas - normally areas with voltages likely to be outside of statutory limits - are identified. The models are then run to determine constraint thresholds. These then become drivers for network load control settings and input into the network development programmes when solutions are required.

6.2.18.2 Asset Efficiency Monitoring: Process for Ensuring Defects Identified By Inspection, Tests and Condition Monitoring Programmes Are Rectified

6.2.18.2.1 Power factor and network losses process for ensuring defects identified by inspection, testing and condition monitoring programmes

As detailed in other sections, poor power factor is caused in the TLC network mostly as a consequence of distributed generation and to a lesser extent by industrial load. The higher the injection power factor of distributed generation, the lower the capacity that generally can be injected into the network as the voltage at light load times quickly becomes too high.

TLC has a draft agreement with Transpower for an exemption from grid exit power factor requirements at Hangatiki. When technical resources are available exemptions will be applied for at other grid exits. TLC's demand based billing has been introduced across the board to try and encourage customers to improve power factor. TLC is also concerned that the encouragement of the use of low cost compact fluorescent lamps and heat pumps, which generally have poor power factors, will have a long term detrimental effect on network efficiency.

TLC believes the best place for power factor correction is demand side management but recognises that long term it may be forced to invest in power factor correction within the distribution system. (The preferred option is demand side.) As a consequence one of the criteria used in selecting voltage regulators and tap changers is to ensure controllers are capable of controlling potential future capacitor banks. (Note: As part of the 2011/12 plan, TLC is setting up two mobile capacitor banks for use when the network is under stress in alternative supply configurations.)

Losses are related to power factor and network development solutions. Losses are a consideration for network planning and demand billing is focused on trying to minimise demand growth and the exponential impact on losses.

6.2.18.2.2 Network constraints: Inspection, testing and condition monitoring practices

Network modelling is used to identify network constraints. Measurements are used from time to time to verify these. The constraint levels are used to set the master load controller with appropriate network settings. These settings are independent of Transpower Regional Co-Incidental Peak Demand (RCPD)

6.2.18.3 Asset Efficiency Monitoring: Systemic Problems and Solutions

The systemic problems with asset efficiency monitoring and the solutions are summarised in Table 6-15.

ASSET EFFICIENCY MONITORING SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Steps to Address**
Incorrect readings due to instrument calibration.	» Ensure good quality instruments are used that have calibration checked regularly. » Ensure substation and equipment maintenance programmes check and ensure transducer calibration and recording equipment is accurate.
Incorrect retailer energy data.	» Source data (at a cost) from the reconciliation manager.
Reducing network power factor.	» Encourage demand side correction. » Allow for future network correction when equipment is being selected.
The level of network constraint is below a realistic load control set point.	» Develop the network in a way that removes constraints. » Manage set points so that the level of non-compliance risk is acceptable.

TABLE 6-15: SYSTEMIC PROBLEMS AND SOLUTIONS IN ASSET EFFICIENCY MONITORING

6.2.19 Forward Maintenance Expenditure Projections

The following sections give budget predictions for maintenance activities broken down by asset category for the planning period. Unless stated otherwise, the figures are in current dollars and have been adjusted for inflation (3%).

6.2.19.1 Lines Maintenance

Table 6-16 lists the lines maintenance predictions by asset category for the planning period.

LINE MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
LV Lines	34,778	35,821	36,896	38,003	39,143	40,317	41,527	42,772	44,056	45,377	46,739	48,141	49,585	51,073	52,605
11 kV Lines	72,100	74,263	76,491	78,786	81,149	83,584	86,091	88,674	91,334	94,074	96,896	99,803	102,797	105,881	109,058
33 kV Lines	51,500	53,045	54,636	56,275	57,964	59,703	61,494	63,339	65,239	67,196	69,212	71,288	73,427	75,629	77,898
Streetlights	20,600	21,218	21,855	22,510	23,185	23,881	24,597	25,335	26,095	26,878	27,685	28,515	29,371	30,252	31,159
Disconnects for Safety	57,179	58,895	60,662	62,482	64,356	66,287	68,275	70,323	72,433	74,606	76,844	79,150	81,524	83,970	86,489
TOTALS	236,157	243,242	250,539	258,056	265,797	273,771	281,984	290,444	299,157	308,132	317,376	326,897	336,704	346,805	357,209

TABLE 6-16: LINES MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.2 Cable Maintenance

Table 6-17 lists the cable maintenance predictions by asset category for the planning period.

CABLE MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Cable LV	10,300	10,609	10,927	11,255	11,593	11,941	12,299	12,668	13,048	13,439	13,842	14,258	14,685	15,126	15,580
Cable 33/11 kV	57,819	59,554	61,340	63,180	65,076	67,028	69,039	71,110	73,243	75,441	77,704	80,035	82,436	84,909	87,457
Cable Ski Fields	11,255	11,592	11,940	12,298	12,667	13,047	13,439	13,842	14,257	14,685	15,126	15,579	16,047	16,528	17,024
Cable Location	1,157	1,191	1,227	1,264	1,302	1,341	1,381	1,423	1,465	1,509	1,554	1,601	1,649	1,699	1,750
Ground Pillar Box Repairs	33,765	34,778	35,822	36,896	38,003	39,143	40,318	41,527	42,773	44,056	45,378	46,739	48,141	49,586	51,073
TOTALS	114,296	117,725	121,257	124,894	128,641	132,500	136,475	140,570	144,787	149,130	153,604	158,212	162,959	167,848	172,883

TABLE 6-17: CABLE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.3 Faults and Standby

Table 6-18 lists the Faults and Standby cost estimates for the planning period.

FAULTS & STANDBY COSTS PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
LV Lines	298,700	307,661	316,891	326,398	336,189	346,275	356,663	367,363	378,384	389,736	401,428	413,471	425,875	438,651	451,811
11kV Lines	515,000	530,450	546,364	562,755	579,637	597,026	614,937	633,385	652,387	671,958	692,117	712,880	734,267	756,295	778,984
33kV Lines	72,100	74,263	76,491	78,786	81,149	83,584	86,091	88,674	91,334	94,074	96,896	99,803	102,797	105,881	109,058
Substations	34,778	35,821	36,896	38,003	39,143	40,317	41,527	42,772	44,056	45,377	46,739	48,141	49,585	51,073	52,605
Standby	214,467	220,901	227,528	234,353	241,384	248,626	256,084	263,767	271,680	279,830	288,225	296,872	305,778	314,951	324,400
TOTALS	1,135,045	1,169,096	1,204,169	1,240,294	1,277,503	1,315,828	1,355,303	1,395,962	1,437,840	1,480,975	1,525,404	1,571,167	1,618,302	1,666,851	1,716,856

TABLE 6-18: FAULTS AND STANDBY PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.4 Zone Substation Maintenance

Table 6-19 lists the Zone substation maintenance predictions broken down by activity for the planning period.

ZONE SUBSTATION MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Planned Maintenance	133,900	137,917	142,055	146,316	150,706	155,227	159,884	164,680	169,621	174,709	179,950	185,349	190,909	196,637	202,536
Unplanned Maintenance	20,600	21,218	21,855	22,510	23,185	23,881	24,597	25,335	26,095	26,878	27,685	28,515	29,371	30,252	31,159
Battery Charger Replacement	23,186	23,882	24,598	25,336	26,096	26,879	27,686	28,516	29,372	30,253	31,160	32,095	33,058	34,050	35,071
Buildings	23,186	23,882	24,598	25,336	26,096	26,879	27,686	28,516	29,372	30,253	31,160	32,095	33,058	34,050	35,071
Protection & Control	17,389	17,911	18,449	19,002	19,572	20,159	20,764	21,387	22,028	22,689	23,370	24,071	24,793	25,537	26,303
Substation Grounds	7,210	7,426	7,649	7,879	8,115	8,358	8,609	8,867	9,133	9,407	9,690	9,980	10,280	10,588	10,906
Substation Energy Costs	18,540	19,096	19,669	20,259	20,867	21,493	22,138	22,802	23,486	24,190	24,916	25,664	26,434	27,227	28,043
Rates & General Maintenance	12,360	12,731	13,113	13,506	13,911	14,329	14,758	15,201	15,657	16,127	16,611	17,109	17,622	18,151	18,696
Rents for Zones and GMTs	9,274	9,552	9,839	10,134	10,438	10,751	11,074	11,406	11,748	12,101	12,464	12,838	13,223	13,619	14,028
Transformer - Planned	92,742	95,525	98,390	101,342	104,382	107,514	110,739	114,061	117,483	121,008	124,638	128,377	132,228	136,195	140,281
Transformer - Unplanned	20,600	21,218	21,855	22,510	23,185	23,881	24,597	25,335	26,095	26,878	27,685	28,515	29,371	30,252	31,159
TOTALS	378,989	390,358	402,069	414,131	426,555	439,352	452,532	466,108	480,091	494,494	509,329	524,609	540,347	556,557	573,254

TABLE 6-19: ZONE SUBSTATION MAINTENANCE PREDICTIONS FOR PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.5 Distribution Transformer and Site Maintenance

Table 6-20 lists the Distribution transformer and site maintenance predictions broken down by activity for the planning period.

DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
GMT Maintenance: Hazard Elimination Projects	45,020	46,371	47,762	49,195	50,671	52,191	53,757	55,369	57,030	58,741	60,503	62,319	64,188	66,114	68,097
GMT Maintenance: Paint and Other Works	33,765	34,778	35,822	36,896	38,003	39,143	40,318	41,527	42,773	44,056	45,378	46,739	48,141	49,586	51,073
Pole & GMT Workshop Refurbishment	61,903	63,760	65,673	67,643	69,672	71,763	73,915	76,133	78,417	80,769	83,192	85,688	88,259	90,907	93,634
Transformer Changes for Corrosion, etc.	10,300	10,609	10,927	11,255	11,593	11,941	12,299	12,668	13,048	13,439	13,842	14,258	14,685	15,126	15,580
SWER Isolating & Distribution Earth Improvements	41,200	42,436	43,709	45,020	46,371	47,762	49,195	50,671	52,191	53,757	55,369	57,030	58,741	60,504	62,319
Other Site Distribution Transformer Maintenance	5,628	5,797	5,971	6,150	6,334	6,524	6,720	6,922	7,129	7,343	7,563	7,790	8,024	8,265	8,513
TOTALS	197,817	203,751	209,864	216,160	222,644	229,324	236,203	243,290	250,588	258,106	265,849	273,824	282,039	290,500	299,215

TABLE 6-20: DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.6 Network Equipment Maintenance

Table 6-21 lists other network equipment maintenance predictions broken down by asset activity for the planning period.

NETWORK EQUIPMENT MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Northern Load Plant	24,344	25,074	25,827	26,601	27,399	28,221	29,068	29,940	30,838	31,763	32,716	33,698	34,709	35,750	36,823
Southern Load Plant	25,750	26,523	27,318	28,138	28,982	29,851	30,747	31,669	32,619	33,598	34,606	35,644	36,713	37,815	38,949
SCADA	34,778	35,821	36,896	38,003	39,143	40,317	41,527	42,772	44,056	45,377	46,739	48,141	49,585	51,073	52,605
Repeater Sites	17,510	18,035	18,576	19,134	19,708	20,299	20,908	21,535	22,181	22,847	23,532	24,238	24,965	25,714	26,485
Repeater Sites Rentals	7,210	7,426	7,649	7,879	8,115	8,358	8,609	8,867	9,133	9,407	9,690	9,980	10,280	10,588	10,906
Radio Licenses	28,982	29,852	30,747	31,670	32,620	33,598	34,606	35,644	36,714	37,815	38,950	40,118	41,322	42,561	43,838
Headend Voice Radio	14,420	14,853	15,298	15,757	16,230	16,717	17,218	17,735	18,267	18,815	19,379	19,961	20,559	21,176	21,812
Line Circuit Breaker	38,316	39,465	40,649	41,869	43,125	44,419	45,751	47,124	48,538	49,994	51,494	53,038	54,629	56,268	57,956
Line Regulator	40,170	41,375	42,616	43,895	45,212	46,568	47,965	49,404	50,886	52,413	53,985	55,605	57,273	58,991	60,761
Fuse Switch	5,150	5,305	5,464	5,628	5,796	5,970	6,149	6,334	6,524	6,720	6,921	7,129	7,343	7,563	7,790
Strategic Spares Storage	23,186	23,882	24,598	25,336	26,096	26,879	27,686	28,516	29,372	30,253	31,160	32,095	33,058	34,050	35,071
Generator Truck	11,593	11,940	12,299	12,668	13,048	13,439	13,842	14,258	14,685	15,126	15,580	16,047	16,528	17,024	17,535
TOTALS	271,409	279,551	287,938	296,576	305,473	314,638	324,077	333,799	343,813	354,127	364,751	375,694	386,964	398,573	410,531

TABLE 6-21: OTHER NETWORK EQUIPMENT MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.7 Vegetation Control Maintenance

Table 6-22 lists the vegetation control maintenance predictions for the planning period.

VEGETATION CONTROL MAINTENANCE PREDICTIONS															
Classification	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Recoveries	-34,102	-35,125	-36,179	-37,264	-38,382	-39,534	-40,720	-41,941	-43,200	-44,496	-45,831	-47,206	-48,622	-50,080	-51,583
Initial Work	203,940	210,058	216,360	222,851	229,536	236,422	243,515	250,820	258,345	266,095	274,078	282,301	290,770	299,493	308,478
Maintenance of Existing	475,860	490,136	504,840	519,985	535,585	551,652	568,202	585,248	602,805	620,889	639,516	658,702	678,463	698,816	719,781
TOTALS	645,698	665,069	685,021	705,571	726,738	748,541	770,997	794,127	817,951	842,489	867,764	893,797	920,611	948,229	976,676

TABLE 6-22: VEGETATION CONTROL MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

6.2.19.8 Summary Maintenance Activities

Table 6-23 lists forward budgets for summary of maintenance activities by asset category.

SUMMARY OF DIRECT MAINTENANCE COST ESTIMATES															
Description	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Line Maintenance	236,157	243,242	250,539	258,056	265,797	273,771	281,984	290,444	299,157	308,132	317,376	326,897	336,704	346,805	357,209
Cable Maintenance	114,296	117,725	121,257	124,894	128,641	132,500	136,475	140,570	144,787	149,130	153,604	158,212	162,959	167,848	172,883
Faults and Standby	1,135,045	1,169,096	1,204,169	1,240,294	1,277,503	1,315,828	1,355,303	1,395,962	1,437,840	1,480,975	1,525,404	1,571,167	1,618,302	1,666,851	1,716,856
Zone Substation Maintenance	378,989	390,358	402,069	414,131	426,555	439,352	452,532	466,108	480,091	494,494	509,329	524,609	540,347	556,557	573,254
Distribution Transformer Maintenance	197,817	203,751	209,864	216,160	222,644	229,324	236,203	243,290	250,588	258,106	265,849	273,824	282,039	290,500	299,215
Network Equipment Maintenance	271,409	279,551	287,938	296,576	305,473	314,638	324,077	333,799	343,813	354,127	364,751	375,694	386,964	398,573	410,531
Vegetation Control	645,698	665,069	685,021	705,571	726,738	748,541	770,997	794,127	817,951	842,489	867,764	893,797	920,611	948,229	976,676
TOTAL DIRECT COST ESTIMATES	2,979,410	3,068,792	3,160,856	3,255,682	3,353,352	3,453,952	3,557,571	3,664,298	3,774,227	3,887,454	4,004,077	4,124,199	4,247,925	4,375,363	4,506,624

TABLE 6-23: FORWARD BUDGET SUMMARY FOR MAINTENANCE ACTIVITIES (INFLATION ADJUSTED)

Table 6-24 lists forward budgets for summary of maintenance activities by asset category. The figures are in current dollars without CPI.

SUMMARY OF DIRECT MAINTENANCE COST ESTIMATES WITHOUT CPI															
Description	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Line Maintenance	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279	229,279
Cable Maintenance	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967	110,967
Faults and Standby	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985	1,101,985
Zone Substation Maintenance	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950	367,950
Distribution Transformer Maintenance	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055	192,055
Network Equipment Maintenance	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504	263,504
Vegetation Control	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891	626,891
TOTAL DIRECT COST ESTIMATES	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631	2,892,631

TABLE 6-24: FORWARD BUDGET SUMMARY FOR MAINTENANCE ACTIVITIES WITHOUT CPI

The data are represented in disclosure format in Section 9. (Note: Section 9 and the disclosure definitions do not specify all of the activity costs included in this section (6.2.19) and, as a consequence, will not reconcile exactly, but will generally.) The summary table 6-23 figures are in current dollars adjusted forward for inflation. Table 6-24 figures are in current dollars without cpi.

Long-term maintenance expenditure is expected to increase at about the rate of inflation. It is generally accepted that capital expenditure will reduce maintenance costs in the long term. Due to the amount of renewal needed, this will be beyond the planning period included in this Plan. Analysis work completed to date of TLC cost structures would suggest this is true, but the amount of costs that capital expenditure will affect is relatively small. For example, most of the time-based work will still be required. There will be a drop off in faults and emergent work costs. Numbers included to date would suggest this saving would be only in the order of 5 to 10% of direct maintenance and associated overhead costs.

Emergent work is generally reducing, but perturbations occur when repairs are necessary after storms and other abnormal events.

6.3 Description of Asset Renewal and Refurbishment Policies

TLC's refurbishment policy is based on renewing equipment that cannot be maintained and/or is no longer fit for purpose. As stated in other sections, the TLC network has not experienced growth like other areas in New Zealand and, therefore, there has been no need to upgrade components. This, coupled with the original construction being completed at the lowest possible cost, resulted in network performance not meeting customers' expectations in 2002. Successful programmes have since been put in place to improve reliability. There are, however, still some pockets of the network that these programmes have not reached and customers are experiencing a lower reliability level than they require.

The concept of short term risk identifying patrols and a 15 year inspection and renewal cycle that looked at overall security was initiated in the 2003/04 year. Since this time the concept has been regularly reviewed and developed. The most important spokes in the overall network wheel were addressed first. The importance of how each section of line contributes to revenue and the need to not over-invest has always been a key consideration.

Analysis work has shown that lines inspectors are recommending about 10% to 20% of poles and lines they inspect be renewed due to aged or poor condition. Further analysis of selected areas has shown that, if line renewals are based on the ideal strengths from design codes, about 30% of poles should be replaced. TLC customers cannot afford to fund this and, as a consequence, a level of compromise based on acceptable risks is applied, particularly in the more rural areas. Reducing renewals below levels in this plan will mean hazards are not being addressed to stakeholder expectations.

One of the other issues facing TLC is that much of the legacy equipment such as substation enclosures, switchgear, ground-mounted transformers and other equipment does not meet present day hazard expectations. A large proportion of the renewal work in the planning period will involve removing and minimising the hazards this equipment presents. Almost all renewals have an effect on hazard reduction.

6.3.1 Overhead Line Renewal Policies and Procedures

The TLC network consists of approximately 5,000 km of overhead lines. Just under 10% of this distance consists of 33 kV lines, 10% is LV lines and the remaining 80% is 11 kV lines in various configurations.

The pole population is mixed with about one third wood, one third iron rail and one third concrete. The lines are generally old and many components are from the original construction. Few of the lines are on the roadside with most in remote rugged hill country. The iron rails typically spent the first 50 years of their life carrying trains. In the 1950s these were removed from the railway lines and the sections of track have carried power lines for the last 60 or so years. In addition to these recycled steel members much of the hardware was also recycled from earlier use in transmission lines (typically suspension insulators).

Customers are deemed to own lines from the point of connection at all voltages. The point of connection is normally where the line to their particular property taps off the main line.

As described in earlier sections, line assets have been broken into asset groups. These asset groups form the basis for renewal planning and performance measurement. The asset groups aggregate up to the service level standards described in earlier sections. The renewal programme consists of a matrix of these asset groups prioritised and arranged into a consistent 15 year cyclic programme. The cost estimates from this matrix produce the annual and long term estimates.

6.3.1.1 Planned Overhead Renewals Policies and Procedures

Once the data are gathered by lines inspectors as described in earlier sections, a detailed review of the asset group takes place. The long term asset programme consists of these asset groups laid out and estimates have been allowed that drive into the long term plan, assuming about a 10% to 15% pole replacement level.

Overall considerations include:

- Hazard elimination/minimisation.
- Faults data.
- Equipment and transformer earth test and earthing systems inspection data.
- Service level performance.
- Importance of the line to the network, including long term significance and income generation. (Models have been put together based on accepted disclosure criteria to calculate sections of feeders that are uneconomic. These models will continue to be developed and more data on assets revenue generation ability will become available during the planning period.)
- Other customer and landowner driven issues.
- Estimate of project costs in the long term plan.

The engineering analysis includes:

- Consideration of any hazards.
- Checking of line strengths required on renewal.
- Evaluation of alternative designs.
- Selection of renewal design options.
- Specification and preparation of plans including earthing improvements and labelling.
- The potential for non-asset solutions including alternative supplies.

The administration functions include:

- Entering and reconciling inspection data with previous records.
- Filing and linking photographs.
- Preparing packages for engineering consideration.
- Taking engineering results and putting together work packages.
- Issuing work packages and updating asset records.
- Detailing material requirements.
- Monitoring spends against estimate.
- Issuing audit packages.
- Receiving audit packages back from auditors.
- Issuing non-compliance notes.
- Follow-ups.
- Related records updated.

The renewal trigger criteria for components of overhead lines does vary depending on importance, geographical location and other practical “real world” issues.

In summary the trigger criteria are:

Poles

- Failure of pole test.
- Bad splitting etc. that will probably deteriorate excessively in the next 15 years.
- Iron rails that have extensive corrosion.
- Concrete poles that are cracked or have large amounts of reinforcing showing.
- Poles that, when a line review is done, are well under strength for the situation they are in, to the point that they will fail at wind strengths in the 100 to 120km/hr. range.
- Conductor height above ground.
- Other rot or corrosion that means a structure cannot perform to expectations.

It should be noted that the programme does not replace iron rail poles as a matter of course. Iron rail poles are only replaced if they are corroded or obviously under strength. The cost of wholesale replacement of iron rail poles would add significant additional funding difficulties to the renewal programme.

Cross arms

- Decay that will not allow them to last another 15 years.
- Too short for the span lengths.

Note: Care is taken not to change cross arms too early. Most are rotten, to the extent that daylight can be seen through them, before they are recommended for changing.

Insulators

1950s 830 type insulators, and 3320 type insulators that are susceptible to fertiliser build up and discharges, are replaced when poles or cross arms are changed.

Conductor

Conductor is renewed when it shows signs of corrosion that will lead to failure in next 15 years. (Conductor is not usually renewed unless broken strands are obvious, if there are large numbers of joints, or there has been a recent history of failures, sometimes due to corrosion, in the section of line being renewed.)

Environmental

Slips, forest, reserves, rivers, access, and other environmental factors.

Landowner and Land Use

Various landowner and land use issues may influence the trigger criteria. Once field data have been measured against these criteria, engineering analysis is completed and asset performance data are considered, asset group work packages are put together. They are issued to the service provider.

Once the service provider has the job pack, a pre job briefing takes place between the sites works controller and the asset management group. The objective of the briefing, which may include an on-site visit, is to:

- Identify and develop on site control measures for any hazards associated with the project.
- Outline the renewal decisions made and the reasons for these.
- Discuss landowner and site access.
- Develop outage plans.
- Discuss other local and individual project issues.

At the completion of works, an audit against specifications takes place. Poles, and a selection of cross arms that have been removed, are inspected and analysed from at least one renewal project annually to ensure the renewal decision was correct. The results of this analysis are discussed at a post job briefing. (All poles removed are also photographed and filed in the asset database and these form a basis for much of the analysis and discussions around the renewal decisions made and the justification for these. This process leads to continuous improvement and review practices.

6.3.1.2 Unplanned Overhead Line Renewal Polices and Procedures

The unplanned renewals and high risk repairs focus on maintaining supply and minimising/eliminating the hazards in the immediate area. High risk repairs that are more complex and need attention before the next planned renewal cycle in that area are inspected and specifications are produced for contractors. The focus of these is to repair the problem to present day design criteria outlined in the previous section, but confine this to the immediate problem area. Examples of this type of work include under height conductors and red tagged poles that have to be changed within three months for compliance.

These emergent repairs, however, should be to a standard that do not require total rework when the next 15 year cycle is completed. Emergency repairs after faults are often temporary and will maintain supply until inspected by lines inspectors or a line designer. The workflows as described in earlier maintenance sections are then followed to ensure the best option is taken for the permanent, emergent repairs. As described in Section 6.1 and 6.2, the planned line inspection and renewal process is based on a 15 year cycle in addition to patrols, which take care of short term hazards and reliability issues.

The principal reasons for this cycle are:

Compliance

The Electricity Regulations require the owners of works to have an inspection programme in place that ensures asset hazards are minimised or eliminated and the safety management system is complied with.

Level of Funding

TLC's customers have limited ability to pay. This means that, unless funds come from some other source, TLC is limited in the size of the renewal programme that can be undertaken. (It should be noted that there are customers in the TLC network area who do not have the means to pay for a network connection and have chosen to disconnect their installations from the network.)

Cost of Inspection and Design Review

TLC has about 50,000 poles. On average, it takes 2 hours inclusive of overheads to assess the condition of a pole. A 15 year cycle equates to approximately two to three labour units and a cost of about $170,000 to $200,000 per annum. (Unplanned work and supervision etc. is in addition to these costs.) Funding of this cost fits into the present matrix of the organisation's charging policies and cost structures.

Consistent decision making

Determining the condition of overhead lines is not black and white. In general, the longer the period between judgement calls, the more consistent the call. Hence, the judgement call on whether an item of hardware will last 15 years as opposed to say 5 is easier to make and experience has shown that more consistent calls are made. Experience has also shown that assets are not renewed too early when removed items are analysed. (Comment made based on the post project briefing process and examination of removed pole photographs.)

Experience with pole testing

Pole testing results from other organisations show that once a segment of line has been pole tested and then retested 10 years later, the failure rate for decay in the ten year period is low. This means there is not a lot of gain to be had by retesting at ten years, but the feeling was that 15 years would be the maximum acceptable period between tests.

Resources available to TLC

The output of a detailed asset condition assessment generally produces a gap between present condition and target condition. Work planning and design therefore has to be done to bring assets up to a suitable standard. It is important that the organisation has the people to do this work in a timely manner. In TLC's case it was estimated that the organisation could cope with the work levels that a fifteen-year cycle would generate. It could not cope with a five year cycle unless the asset age was globally improved first.

Landowner concerns

Landowners are becoming increasingly concerned about work on overhead power lines through their land. The 15 year cycle minimises the need to repeatedly enter land.

Establishment/Disestablishment Costs

The 15 year programme minimises contractors' familiarisation and establishment/disestablishment costs. Short-term small scattered projects add cost when compared to a more planned approach.

Other points associated with this programme that need to be understood include:

Patrols for High Risk Defects

The 3 yearly 11 kV and shorter cycle patrols of urban areas and 33 kV lines (as described in earlier sections) coupled with fault patrols take place and identify any "short term" or urgent issues.

Project Management: Project reviews

TLC places a significant amount of importance on continuous improvement and the need for staff and stakeholders at all levels to be able to understand renewal programmes and contribute to the continuous improvement process. Pre and post project briefings reviews take time. Shorter cycles would reduce our ability to complete this process comprehensively and, as a consequence, the learning process would not develop as quickly. The continuous improvement process is leading to cost savings and focuses heavily on hazard control. In saying this, the 15 year programme is also reviewed and reconsidered to ensure that it is still a relevant strategy.

Overall Analysis and Data

The 15 year cycle produces data and information that allows detailed analysis and long term solutions to be found, including the consideration of non asset solutions. This often involves complex landowner discussions. Considerably more resource and cost would be needed to handle data analysis, resolution of landowner issues and other planning and design issues if a shorter cycle were adopted.

The repairs, after high risk defects are found during patrols, focus on ensuring that the structure or structures are serviceable until the planned works programme completes renewal of the asset group within which the assets are located. The 15 year cycle is wider than just the lines. Other renewals in an area are completed at the same time while resources are in the region.

For example, as mentioned earlier, the condition of distribution transformers is assessed and units in poor condition are changed. Landowners are also notified of private lines in poor condition and fuses are installed at the tap-off points. Transformer earthing is tested and checked. The programme is focused on asset groups (typically 10km lengths of line) and the areas receiving attention, in any year, are spread throughout the network. A long term plan is being followed, cycling through asset groups.

It should also be noted that local knowledge and a detailed knowledge of each line asset including such things as how exposed lines are on hill tops, landowners, and a multitude of other issues are also in the back of one's mind when line renewal work is being planned. There are also a number of short term issues like slips, storms, landowners' needs, etc. that create a level of unplanned work needs.

6.3.2 Other Equipment Renewal Policies and Procedures

6.3.2.1 Policies and Procedures: Zone Substation, Voltage Control, Distribution Substations, Cables, Switchgear and Other Distribution Asset Renewal (excluding Line Renewal)

This section covers the capital expenditure primarily associated with replacement and refurbishment of existing assets. This work is to maintain the network and equipment to meet target levels of service.

The policy is to renew when the existing equipment will cost more to refurbish than renew or it is not possible to refurbish up to a level that will meet present day hazard control, operational or customer service targets. This means for example that if a relatively major component fails in an item of switchgear, and it is not possible to get suitable parts that will ensure the switch will operate reliably, then it would be replaced with a present day equivalent.

The general principle of economic evaluation is to use regulatory cost for the particular piece of equipment that has failed. If the cost of refurbishment is greater than the regulatory cost, then it would generally be renewed. The ages used in depreciation calculations are those in the Commerce Commission disclosure handbooks.

The factors that may modify this approach are:

- Parts availability.
- Availability of equivalent replacements.
- Importance in network, i.e. how long and what are the risks of equipment being out of service for either refurbishment or renewal periods.
- Any other justified technology gains or other advances by renewal.
- On-going guaranteed reliability of renewal vs. refurbishment.
- TLC's pricing models for the area or local area that show the regulatory valuation and level of return being generated.

The renewal or refurbishment is triggered by:

- An emergent failure where equipment either has to be renewed or refurbished to keep the network operational.
- A 15 year detailed inspection (as described in Sections 6.1 and 6.2) and review of the assets.
- Test results that indicate the need for renewal or refurbishment. An example of this is oil test results and other transformer tests that signal the need for refurbishment.
- Hazard elimination/minimisation issues.
- Customer requests for capacity changes.
- Environmental issues.
- Equipment identified to be at the end of its life.

If equipment is old but in good operational condition and meets service expectations, then it would not be considered for refurbishment or renewal.

Generally, when good quality parts are available and repairs can be done to a standard that will ensure reliability and the cost is below regulatory cost and the equipment will last to periods expected, then refurbishment takes place as opposed to renewal. The expected lives used in assessments are those listed in the information disclosure handbook for valuations of lines companies. (TLC's experience is that these life lengths are a reasonable expectation.) Examples of equipment that would be renewed because they would not meet the refurbishment criteria in each of the asset sub categories are:

Zone Substations

- Electro mechanical relays that stops operating or are not meeting test criteria.
- Batteries that are outside manufacturer's age criteria or are not testing correctly.
- Hardware that is corroded.
- Insulators that are cracking or have failed.
- Other equipment that has failed and if repaired cannot be trusted to give reliable service.
- Low, inadequate fencing.
- Underrated switchgear.
- Conductor with low clearance into structures.
- Equipment that is exposed to fault current greater than ratings.

Voltage Control

- Old regulators are replaced when they have failed and parts are no longer available.
- Electro mechanical voltage relays are replaced on failure or when it becomes difficult to adjust them to the operating requirements of the network.

Distribution Substation

- Ground mounted substations are replaced when they are found to be in poor condition and maintaining them on site is not an option.
- On failure of integral LV or HV switchgear.
- When there is a lack of, or underrated, HV and LV switchgear and this equipment is part of the structure.
- When the operation of HV or LV equipment places the operator at risk of contact with live conductors or an arc flash.
- When a site has a high risk of vehicle impact.
- When structures or enclosures can be accessed easily by the public.
- When inspections or tests show that earthing systems are inadequate.
- When ground mounted enclosures with dropper wires coming down are found to be hazardous.

Cables

- Cables are replaced when test results indicate that joining pieces together will no longer give reliable operation.
- When live terminals on termination structures have less ground clearance than specified in the codes of practice.

Switchgear

- When it fails and parts are no longer available.
- Underrated or has a possibility of putting the operator or public at risk.

Distribution Transformers

- On failure or when they are in poor condition and the cost of repair is greater than the regulatory value. (If repair costs are greater than this then the unit would be written off.)
- If bushing arrangements, tapping ranges and other fixtures do not allow unit to be used in structure layouts and the cost of altering a unit is greater than the regulatory value.

6.3.2.2 Policies and Procedures: SCADA, Communication Equipment and Other Related Equipment Renewal

The policy of renewing and refurbishing this equipment is to do it in a way that keeps the systems current, serviceable and avoids, as far as practical, the need to replace large amounts of equipment at one time due to it becoming obsolete.

The reasons for this policy include:

- The importance of the equipment in operating the network to meet expected levels of service.
- The speed with which technology is advancing.
- The cost and technical resource needed for a one off upgrade.

Typically this policy results in equipment that is greater than 15 years old being progressively renewed.

SCADA

SCADA equipment is renewed on failure and on an on-going basis typically after 15 years' service or when it is no longer supported. TLC works closely with an independent specialist SCADA Engineer/Technician to review the equipment annually and select equipment that is not performing or obsolete and in need of renewal. Priority is placed on key equipment that has a significant impact on the overall system operation.

This strategy has resulted in relatively few failures of equipment and, when they do occur, repairs can be quickly completed because parts and support are available.

Communication Equipment

TLC works closely with an independent specialist communications Engineer/Technician to review the equipment annually and select equipment that is not performing or is obsolete and in need of renewal. Priority is placed on key equipment that has a significant effect on the overall system operation.

Examples of equipment that would be renewed as not meeting the refurbishment criteria for communication equipment are:

- Batteries that are old or are not testing correctly.
- Aged radio sets that have failed and that are no longer supported by the manufacturer.
- Radio aerials and hardware that have failed or when a frequency adjustment is needed as required by the spectrum allocations regulator.

(Note: TLC is slowly converting the legacy analogue system to a digital system. The main driver for this is the band width requirements of the spectrum regulator. It should be noted that the system being implemented does not have a high data rate transfer; cost makes high data transfer rate difficult to justify).

6.4 Description and Identification of Renewal or Refurbishment Programmes or Actions to be Taken for each Asset Category, including Associated Expenditure Projections

6.4.1 Detailed Description of the Projects Currently Underway or Planned for the Next 12 Months

6.4.1.1 Line Renewals

The 2012/13 programme targets 377 km of line to be inspected and assessed for renewal. The estimated cost for 2012/13 is $5,389,473 (including an engineering on-cost of 4%). The length is slightly more than previous years due to the way the 15 yearly cycle programme works out with the asset groups. The breakdown of this estimate is detailed in the following sections.

As outlined in earlier sections, before work is issued to the Service Provider, lines are inspected, data are analysed and designs for replacements completed. Asset group work is then packaged up into folders. In addition to work instructions, this documentation includes plans, photographs, landowner details, access details, special requirement forms such as forest entry permits and any special hazard considerations. A pre-job continuous improvement and briefing meeting also takes place.

About 60% of the Line Renewal work is completed internally and 40% by contractors. Once work is completed, audits to specifications are carried out. A post job continuous improvement meeting takes place that, amongst other things, examines the poles removed (either directly or via photographs), and continually reviews, procedures, polices, and other factors that feed into the renewal decisions.

Table 6-25 lists the line renewal projects for 2012/13. At the time of writing, detailed inspections had been completed for about 40% of the projects. A breakdown of activities has been included in the tables for these. It is interesting to note that the expected 10 to 15% pole replacement is tracking higher for the period. Rotten and poor condition poles in many of the projects have pushed this up. Analysis and calculation work based on the inspection to date shows that it is not possible to reduce this, i.e. the poles have to be replaced.

LINE RENEWAL PROJECTS FOR 2012/13								
Point of Supply	**Description**	**Sites Inspected**	**TLC Network Sites**	**Privately Owned Sites**	**Sites Requiring Renewal/ Maint'nce**	**Total Pole Changes**	**% of Network Pole Changes**	**Cost Estimate**
LV LINES								
Hangatiki	Mokau 128-06							42,436
Hangatiki	Waitomo 108-03							63,654
Whakamaru	Mokai 123-04							6,631
LV Line Total								**112,721**
11 kV LINES								
Hangatiki	Aria 114-03							117,333
Hangatiki	Benneydale 103-05							256,879
Hangatiki	Benneydale 103-06	191	158	33	89	44	28%	138,828
Hangatiki	Hangatiki East 102-03	71	55	16	34	23	42%	63,045
Hangatiki	Maihiihi 111-08	160	110	50	54	35		87,743
Hangatiki	McDonalds 110-05							248,251
Hangatiki	Mokau 128-06							375,839
Hangatiki	Mokauiti 115-03				42	33		275,193
Hangatiki	Mokauiti 115-04	36	29	7	12	10	34%	137,697
Hangatiki	Waitomo 108-03							103,847
National Park	Raurimu 410-01				28	23		236,500
Ohakune	Turoa 415-03	32	32		14	2	6%	71,143
Ongarue	Ohura 413-05							229,877
Ongarue	Ongarue 421-01				38	16		214,137
Ongarue	Tuhua 422-02	105	68	37	41	26	38%	130,141
Ongarue	Western 403-05	135	109	26	52	28	26%	192,157
Tokaanu	Kuratau 406-01							17,520
Tokaanu	Turangi 423-01							165,500
Tokaanu	Waihaha 426-04	213	123	90	49	31	25%	241,362
Whakamaru	Huirimu 121-02	185	126	59	50	36	29%	109,640
Whakamaru	Tihoi 124-02	275	182	93	95	52	29%	143,075
Whakamaru	Tirohanga 129-01							181,123
Whakamaru	Tirohanga 129-02				55	43		236,202
Whakamaru	Wharepapa 122-08				16	14		77,024
11 kV Line Total								**4,050,057**
33 kV LINES								
Tokaanu	Tokaanu / Kuratau 607-01				18	14		245,106
33 kV Line Total								**245,106**
EMERGENT								
LV Emergent								106,090
11 kV Emergent								669,500
33 kV Emergent								206,000
Total Emergent								**981,590**
TOTAL		**1403**	**992**	**411**	**687**	**430**	**43%**	**5,389,473**

TABLE 6-25: LINE RENEWAL PROJECTS WORK FOR 2012/13

Figure 6-1 indicates the location of the 2012/13 line renewal projects

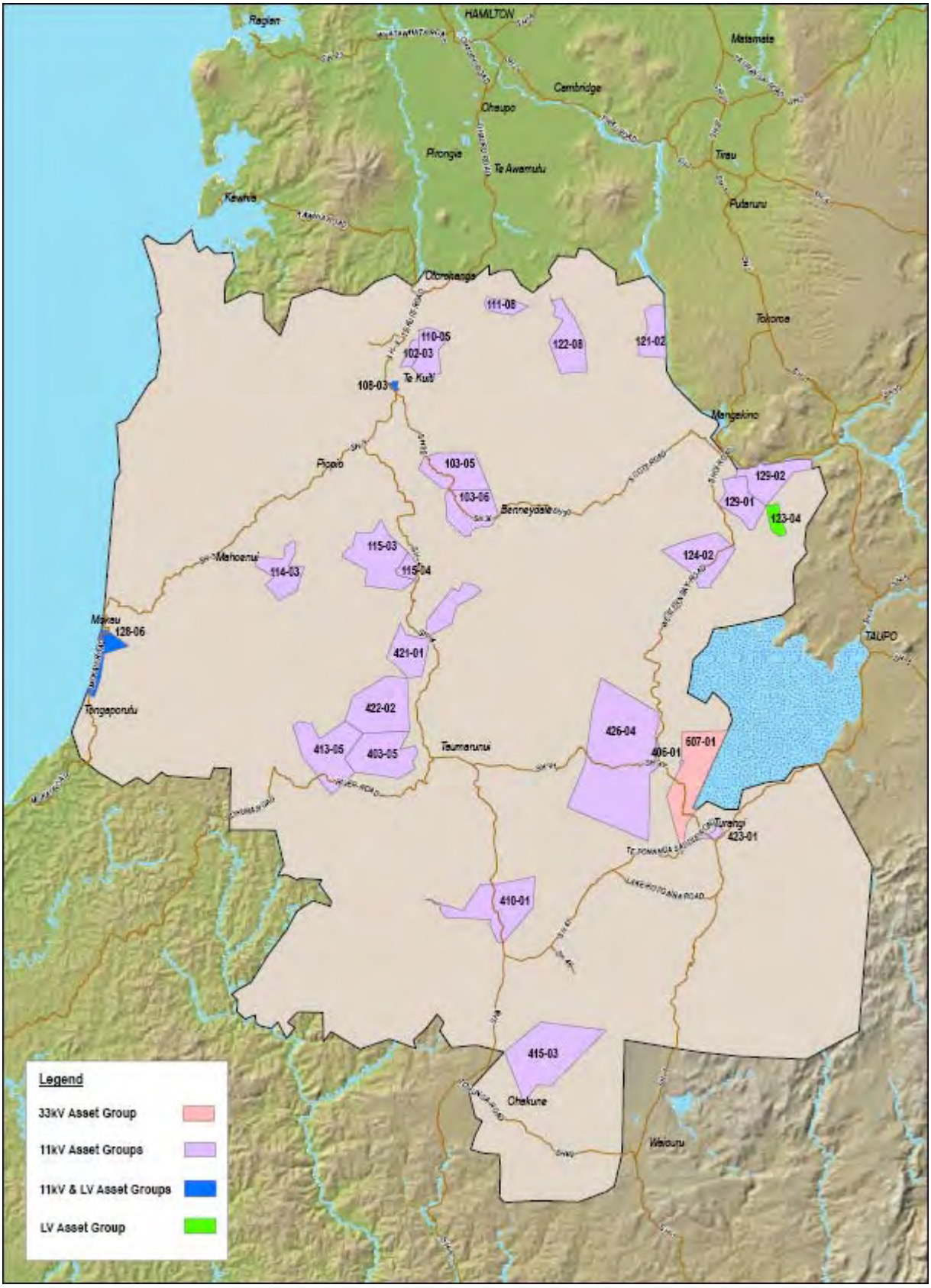


FIGURE 6-1: LOCATION OF 2012/13 LINE RENEWAL PROJECTS

6.4.1.2 Renewals other than Line Renewals

Full details of renewals other than line renewals have been included in section 5. The definitions and expectations of *Renewal*, *Asset Replacement and Development* are confusing if one studies the definitions in the 2008 Commerce Commission Information Disclosure requirements. Specifically, for example, there is an overlap between *Asset Renewal and Replacement* with the development category of *Reliability, Safety and Environmental*. In TLC's case, safety or hazard control expenditure is mostly associated with renewing old outdated hazardous equipment. For the purposes of compliance however the following sections are base on the definition of renewal in the 2008 disclosure information for renewal and asset replacement.

Because of this difficulty, table 6-26 lists the asset renewal and replacement projects (excluding line renewals and substations) in summary form (see section 5 for more detail) proposed for 2012/13 by Point of Supply. The values given are in current dollars, without inflation and inclusive of engineering costs.

2012/13 ASSET RENEWAL AND REPLACEMENT PROJECTS (excluding Line Renewals and Substations)				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	101k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	177k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	107k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Ongarue	Transformers - 2 Pole Structures	Ongarue	T4128 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Look at new options as 04I01 may be overloaded.	30k

2012/13 ASSET RENEWAL AND REPLACEMENT PROJECTS (excluding Line Renewals and Substations)				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Transformers - 2 Pole Structures	Northern	01A50 Rebuild structure 11 kV only 4m above ground. Ground mount transformer, if possible use a second hand 100 kVA.	48k
Ongarue	Transformers - 2 Pole Structures	Northern	06H11 Raise equipment on structure, recloser at only 3.75m above the ground.	48k
Ongarue	Transformers - 2 Pole Structures	Ongarue	04I01 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Check loading on 04I01 as load flow program indicates transformer could be overloaded.	30k
Tokaanu	Transformers - 2 Pole Structures	Oruatua	09U10 Replace with ground mounted transformer. Adjacent high wooden fence makes any structure a hazard.	68k
Tokaanu	Transformers - 2 Pole Structures	Oruatua	09U07 Replace with a ground mounted transformer. Pole requires replacing and LV through trees. Earth mat looks to be damaged.	68k
Tokaanu	Transformers - Ground Mounted	Turangi	10S46 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
Tokaanu	Transformers - Ground Mounted	Turangi	10S31 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
Whakamaru & Mokai	Transformers - Ground Mounted	Mangakino	T706 Install a refurbished 200 kVA transformer.	45k

TABLE 6-26: SUMMARY OF ASSET RENEWAL AND REPLACEMENT PROJECTS FOR 2012/13 EXCLUDING LINE RENEWALS & SUBSTATIONS (WITHOUT INFLATION)

These projects and more detail about them have been included in section 5.

6.4.2 Summary Description of the Projects Planned for the Next 4 Years (2013/14 to 2016/17)

6.4.2.1 Line Renewal Summary

The renewal of lines as part of the 15 year programme is targeted at achieving about 300km of line per year. Table 6-27 provides a summary of the planned line renewal expenditure predictions for the next four years. The figures include a 3% cpi factor.

PREDICTED LINE RENEWAL EXPENDITURE 2013/14 to 2016/17				
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**
LV Planned Line Renewals	14,069	104,335	656,729	498,099
11kV Planned Line Renewals	3,858,709	4,568,898	4,432,676	4,438,336
33kV Planned Line Renewals	819,032	401,190	291,490	520,582
Emergent	1,041,369	1,072,610	1,104,788	1,137,932
Total	**5,733,178**	**6,147,033**	**6,485,684**	**6,594,948**

TABLE 6-27: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT 4 YEARS (INFLATION ADJUSTED)

6.4.2.2 Low Voltage Renewals

The expenditure follows the programme as outlined in the constraints section. Table 6-28 details the Low Voltage line renewals scheduled for the next 4 years and associated expenditure predictions.

LOW VOLTAGE PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS					
Point of Supply	**Description**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Hangatiki	Mahoenui 113-03	7,034			
Hangatiki	Mokau 128-08	7,034			
Ongarue	Manunui 407-01		34,778		
Hangatiki	Benneydale 103-07		69,556		
Hangatiki	Coast 125-05			35,822	
Ongarue	Ongarue 421 -03			29,851	
Tokaanu	Oruatua 506-01			208,959	
Whakamaru	Whakamaru 120-03			119,405	
Ohakune	Ohakune Town 414-01			143,286	147,585
Ohakune	Turoa 415-01			119,405	153,734
Ongarue	Ongarue 421-03				12,299
Tokaanu	Motuoapa 425-01				184,481
	Subtotal	*14,069*	*104,335*	*656,729*	*498,099*
All Areas	Emergent	112,551	115,927	119,405	122,987
Total Planned Expenditure		**126,620**	**220,262**	**776,134**	**621,086**

TABLE 6-28: LOW VOLTAGE PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT FOUR YEARS (INFLATION ADJUSTED)

6.4.2.3 11 kV Line Renewals

Expenditure follows the programme as outlined in the constraints section. Table 6-29 (split into two parts) shows the expenditure allowances to renew the following 11 kV feeder asset groups over the next 4 years. The figures include a 3% cpi factor.

11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2013/14			11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2014/15		
Point of Supply	**Description**	**Estimate**	**Point of Supply**	**Description**	**Estimate**
Hangatiki	Gravel Scoop 109-04	337,414	Hangatiki	Aria 114-04	175,844
Hangatiki	Gravel Scoop 109-05	240,403	Hangatiki	Aria 114-05	285,461
Hangatiki	Mahoenui 113-03	213,773	Hangatiki	Benneydale 103-08	74,437
Hangatiki	Oparure 107-05	234,106	Hangatiki	Caves 101-09	32,618
Hangatiki	Oparure 107-06	234,106	Hangatiki	Caves 101-10	94,185
Hangatiki	Piopio 116-05	141,001	Hangatiki	Gravel Scoop 109-06	304,380
Hangatiki	Rangitoto 106-05	323,955	Hangatiki	Gravel Scoop 109-14	255,103
Hangatiki	Te Kuiti Town 105-01	146,316	Hangatiki	Mahoenui 113-05	266,724
Hangatiki	Te Mapara 117-04	317,009	Hangatiki	Mokau 128-08	528,482
National Park	Raurimu 410-02	245,561	Hangatiki	Mokau 128-09	108,056
Ongarue	Northern 402-05	356,134	Hangatiki	Mokauiti 115-05	222,842
Ongarue	Ohura 413-08	285,993	Hangatiki	Mokauiti 115-06	168,850
Ongarue	Ongarue 421-02	214,312	Hangatiki	Otorohanga 112-07	106,953
Ongarue	Western 403-06	288,770	National Park	National Park 411-02	437,770
Whakamaru	Wharepapa 122-07	279,855	National Park	Raurimu 410-02	252,928
	Subtotal	*3,858,709*	Ohakune	Ohakune Town 414-01	164,896
All Areas	Emergent	710,273	Ongarue	Manunui 407-01	137,480
			Ongarue	Ohura 413-03	177,934
			Ongarue	Southern 409-07	182,269
			Ongarue	Western 403-07	182,649
			Whakamaru	Huirimu 121-03	294,889
			Whakamaru	Tihoi 124-03	114,150
				Subtotal	*4,568,898*
			All Areas	Emergent	731,581
Total Planned for 2013/14		**4,568,981**	**Total Planned for 2014/15**		**5,300,479**

11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2015/16			11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2016/17		
Point of Supply	**Description**	**Estimate**	**Point of Supply**	**Description**	**Estimate**
Hangatiki	Benneydale 103-08	76,670	Hangatiki	Aria 114-06	164,206
Hangatiki	Caves 101-11	57,806	Hangatiki	Benneydale 103-10	309,547
Hangatiki	Coast 125-05	345,461	Hangatiki	Benneydale 103-11	309,337
Hangatiki	Coast 125-06	201,199	Hangatiki	Caves 101-12	293,494
Hangatiki	Mahoenui 113-06	250,089	Hangatiki	Caves 101-13	146,316
Hangatiki	Mahoenui 113-07	120,581	Hangatiki	Gravel Scoop 109-07	362,678
Hangatiki	Maihiihi 111-10	360,513	Hangatiki	Mahoenui 113-08	251,337
Hangatiki	Rural 126-03	3,648	Hangatiki	Maihiihi 109-08	91,249
Hangatiki	Te Mapara 117-06	248,363	Hangatiki	Maihiihi 111-11	169,474
National Park	Raurimu 410-02	260,516	Hangatiki	McDonalds 110-03	97,591
Ohakune	Ohakune Town 414-01	169,843	Hangatiki	McDonalds 110-04	44,800
Ohakune	Turoa 415-01	315,638	Hangatiki	Mokau 128-07	86,794
Ongarue	Nihoniho 412-02	221,068	Hangatiki	Otorohanga 112-05	3,772
Ongarue	Ohura 413-04	321,789	Hangatiki	Otorohanga 112-06	119,720
Ongarue	Ohura 413-09	143,255	National Park	Raurimu 410-03	356,220
Ongarue	Ongarue 421-03	232,045	Ohakune	Ohakune Town 414-01	246,581
Ongarue	Southern 409-08	258,024	Ohakune	Turoa 415-01	325,107
Ongarue	Western 403-03	158,168	Ongarue	Ongarue 421-04	430,941
Ongarue	Western 403-07	188,128	Ongarue	Southern 409-09	207,822
Tokaanu	Oruatua 417-01	252,336	Ongarue	Western 403-04	112,161
Whakamaru	Huirimu 121-04	70,392	Tokaanu	Motuoapa 425-01	117,326
Whakamaru	Pureora 119-03	6,146	Tokaanu	Waiotaka 427-01	191,860
Whakamaru	Whakamaru 120-03	170,998		*Subtotal*	*4,438,336*
	Subtotal	*4,432,676*	All Areas	Emergent	776,134
All Areas	Emergent	753,528			
Total Planned for 2015/16		**5,186,205**	**Total Planned for 2016/17**		**5,214,470**

TABLE 6-29: 11 KV LINE RENEWALS PLANNED EXPENDITURE FOR NEXT 4 YEARS (INFLATION ADJUSTED)

6.4.2.4 33 kV Line Renewals

Expenditure follows the programme as outlined in the constraints section. Table 6-30 shows the expenditure allowances to renew the following 33 kV feeder asset groups over the next 4 years. The figures include a 3% cpi factor.

33kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2013/14 to 2016/17					
Point of Supply	**Description**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Ongarue	Ongarue / Taumarunui 604-01	530,660			
Ongarue	Taumarunui / Kuratau 608-03	254,660			
Ongarue	Tuhua 602-01	33,712			
National Park	National Park 601-01		33,698		
Ongarue	Taumarunui / Kuratau 608-02		367,492		
Ongarue	Taumarunui / Kuratau 608-01			234,367	
National Park	Kuratau Pole Structure 610-01			57,123	
National Park	National Park / Kuratau 609-04				310,814
Hangatiki	Te Waireka Road 303-01				209,768
	Subtotal	*819,032*	*401,190*	*291,490*	*520,582*
All Areas	Emergent	218,545	225,102	231,855	238,810
Total Planned Expenditure		**1,037,577**	**626,292**	**523,345**	**759,392**

TABLE 6-30: 33KV LINE RENEWALS PLANNED EXPENDITURE FOR NEXT 4 YEARS (INFLATION ADJUSTED)

An allowance for emergent work has been included in LV, 11 kV and 33 kV estimates. Emergent work is repairs that have to be completed to maintain supply that requires component renewal that has to be capitalised. This allowance is used from time to time for other, unable to be predicted, urgent needs such as slips, vegetation deviations and similar issues.

The allowance will also be used for costs associated with almost completed jobs at year end that span the balance date due to creditors timing etc.

6.4.2.5 Line Renewal Summary without CPI

Table 6-31 provides a summary of the planned line renewal expenditure predictions for the next four years. The figures are in current year dollars and do not include any adjustment for inflation.

PREDICTED LINE RENEWAL EXPENDITURE 2013/14 to 2016/17 WITHOUT CPI				
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**
LV Planned Line Renewals	13,261	95,481	583,495	429,665
LV Emergent	106,090	106,090	106,090	106,090
Total LV	**119,351**	**201,571**	**689,585**	**535,755**
11kV Planned Line Renewals	3,637,203	4,181,189	3,938,375	3,828,548
11 kV Emergent	669,500	669,500	669,500	669,500
Total 11 kV	**4,306,703**	**4,850,689**	**4,607,875**	**4,498,048**
33kV Planned Line Renewals	772,016	367,146	258,985	449,058
33 kV Emergent	206,000	206,000	206,000	206,000
Total 33 kV	**978,016**	**573,146**	**464,985**	**655,058**
Total Predicted Expenditure	**5,404,070**	**5,625,406**	**5,762,445**	**5,688,861**

TABLE 6-31: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT 4 YEARS WITHOUT CPI

6.4.3 Summary of Asset Renewal and Replacement Projects Planned for 2013/14 to 2016/17 by Point of Supply

Table 6-32 lists the renewal and asset replacement projects (excluding line renewals and substations) for the following 4 years (2013/14 to 2016/17) by Point of Supply. The values are in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	86k
2013/14	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2013/14	Network Equipment Renewal	Whole Network	Protection	11k
2013/14	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2013/14	Network Equipment Renewal	Whole Network	RADIO Specific	160k
2013/14	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
2013/14	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2013/14	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2013/14	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2013/14	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2014/15	Network Equipment Renewal	Whole Network	Have a semi mobile Load Control plant that can be relocated. Reuse the load control plant that is removed from National Park.	68k
2014/15	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	80k
2014/15	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2014/15	Network Equipment Renewal	Whole Network	Load Control	113k
2014/15	Network Equipment Renewal	Whole Network	Protection	11k
2014/15	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2014/15	Network Equipment Renewal	Whole Network	RADIO Specific	171k
2014/15	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
2014/15	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2014/15	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2014/15	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2014/15	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2015/16	Network Equipment Renewal	Whole Network	Semi Mobile containerised 2.5 MVA substation.	450k
2015/16	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	64k
2015/16	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2015/16	Network Equipment Renewal	Whole Network	Protection	11k
2015/16	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2015/16	Network Equipment Renewal	Whole Network	RADIO Specific	151k
2015/16	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
2015/16	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2015/16	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2015/16	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2016/17	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	21k
2016/17	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2016/17	Network Equipment Renewal	Whole Network	Protection	11k
2016/17	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2016/17	Network Equipment Renewal	Whole Network	RADIO Specific	159k
2016/17	Network Equipment Renewal	Whole Network	Relay Changes - Special	67k
2016/17	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2016/17	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2016/17	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2016/17	Network Equipment Renewal	Whole Network	Transformer Renewals	338k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - 2 Pole Structures	Te Kuiti South	T559 Rebuild structure, replace poles, use standard single pole if possible.	56k
2014/15	Transformers - 2 Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	23k
2014/15	Transformers - Ground Mounted	Oparure	T663 Replace with refurbished I tank transformer.	45k
2015/16	Transformers - 2 Pole Structures	Mahoenui	T1865 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
2015/16	Transformers - 2 Pole Structures	Te Mapara	T1777 Rebuild structure with transformer higher up pole. Use standard single pole design if practical.	45k
2015/16	Transformers - 2 Pole Structures	Mahoenui	T1453 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Transformers - 2 Pole Structures	Mahoenui	T2520 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2015/16	Transformers - Ground Mounted	Waitomo	T406 Rebuild to regulations and current TLC standards.	45k
2015/16	Transformers - Ground Mounted	Hangatiki East	T381 Replace with I tank or front access transformer. Use a refurbished transformer if available.	45k
2016/17	Transformers - 2 Pole Structures	Te Mapara	T1829 Check ground clearance - raise transformer on pole.	8k
2016/17	Transformers - 2 Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure.	28k
2016/17	Transformers - Ground Mounted	Oparure	T457 Install a front access transformer 300 kVA with I Blade RTE switch.	45k
2016/17	Transformers - Ground Mounted	Rangitoto	T464 Replace with a refurbished I Tank. Check loading and size transformer appropriately.	45k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Transformers - 2 Pole Structures	National Park	15L05 Transformer is close to motel balcony. Ground mount transformer, check loadings for transformer size.	45k
2014/15	Transformers - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k
2014/15	Transformers - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k
2014/15	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	45k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Transformers - 2 Pole Structures	Turoa	20M08 Ground mount transformer, check loadings.	56k
2015/16	Transformers - 2 Pole Structures	Tangiwai	20L06 Replace structure with ground mounted transformer.	62k
2016/17	Transformers - 2 Pole Structures	Turoa	20M07 Ground mount transformer. Check loadings.	56k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - 2 Pole Structures	Manunui	08K14 Replace pole mounted transformer with refurbished ground mounted transformer.	49k
2014/15	Transformers - 2 Pole Structures	Tuhua	05G03 Lift equipment over regulation height and maintain clearances.	23k
2014/15	Transformers - 2 Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	49k
2014/15	Transformers - 2 Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA transformer.	45k
2015/16	Transformers - 2 Pole Structures	Hakiaha	01B11 Rebuild structure with safer LV wiring. Raise the height of the transformer.	45k
2015/16	Transformers - 2 Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer.	45k
2015/16	Transformers - 2 Pole Structures	Southern	09K50 Check loading on transformer. Either 100 kVA standard single pole or 200 kVA refurbished and mount.	42k
2016/17	Transformers - 2 Pole Structures	Western	08I21 Raise equipment on structure to above regulation height for 11 kV from ground level. Maintain clearances.	56k
2016/17	Transformers - 2 Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	56k
2016/17	Transformers - 2 Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level.	45k
2016/17	Transformers - 2 Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure.	42k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	45k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Transformers - 2 Pole Structures	Oruatua	09U10 Replace with ground mounted transformer. Adjacent high wooden fence makes any structure a hazard.	68k
2012/13	Transformers - 2 Pole Structures	Oruatua	09U07 Replace with a ground mounted transformer. Pole requires replacing and LV through trees. Earth mat looks to be damaged.	68k
2012/13	Transformers - Ground Mounted	Turangi	10S46 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
2012/13	Transformers - Ground Mounted	Turangi	10S31 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
2013/14	Transformers - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer. Downsize transformer as required. Rebuild with standard single pole structure.	28k
2013/14	Transformers - 2 Pole Structures	Waihaha	07Q14 Rebuild structure. Next to State Highway. Existing equipment below regulation height.	56k
2013/14	Transformers - Ground Mounted	Turangi	10S41 Install RTE switch do in conjunction with 10S42.	45k
2013/14	Transformers - Ground Mounted	Turangi	10S42 Install front access transformer with11 kV internal fusing. Do in conjunction with 10S41.	45k
2014/15	Transformers - 2 Pole Structures	Motuoapa	09T04 Replace with ground mounted 300 kVA. Use a refurbished transformer.	56k
2014/15	Transformers - 2 Pole Structures	Kuratau	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available.	39k
2014/15	Transformers - Ground Mounted	Turangi	10S44 Tin shed roadside. Open LV rack in tin shed, messy layout of leads. Replace with ground mounted transformer.	41k
2015/16	Transformers - 2 Pole Structures	Kuratau	09R27 Lift equipment on pole to above regulation height and maintain clearances.	39k
2015/16	Transformers - Ground Mounted	Turangi	10S26 Rebuild to regulations and current TLC standards.	45k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Transformers - Ground Mounted	Turangi	10S29 Rebuild to regulations and current TLC standards.	41k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2012/13	Transformers - Ground Mounted	Mangakino	T706 Install a refurbished 200 kVA transformer.	45k
2013/14	Transformers - Ground Mounted	Mangakino	T701 Check loading and replace with a refurbished I tank of a suitable size. Install a RMU with 2 fuses, one for T2316. Spread cost of RMU over T2316.	45k
2014/15	Transformers - Ground Mounted	Mangakino	T700 Rebuild to regulations and current TLC standards.	45k
2016/17	Transformers - 2 Pole Structures	Mangakino	T1081 Check loading; rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	56k

TABLE 6-32: SUMMARY OF ASSET RENEWAL AND REPLACEMENT PROJECTS (EXCLUDING LINE RENEWALS AND SUBSTATIONS) PLANNED FOR 2013/14 TO 2016/17 BY POINT OF SUPPLY (WITHOUT INFLATION)

6.4.4 Line Renewal Forecast for the Remainder of the Planning Period (2017/18 to 2026/27)

6.4.4.1 Line Renewal Summary

Table 6-33 summarises the planned expenditure for line renewals for the remainder of the planning period. Estimate figures have been adjusted to allow for inflation.

PREDICTED LINE RENEWAL EXPENDITURE SUMMARY FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)										
Description	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
LV Planned Line Renewals	918,408	639,339	477,090	686,261	343,608	931,784	75,629	109,058	478,202	279,331
11kV Planned Line Renewals	4,661,502	4,740,608	4,813,406	4,487,649	5,100,114	5,361,180	4,728,765	4,528,188	5,314,972	6,436,300
33kV Planned Line Renewals	923,697	1,165,587	2,223,605	1,527,236	1,814,449	183,839	723,687	2,756,739	222,372	112,059
Emergent	1,172,069	1,207,232	1,243,449	1,280,752	1,319,174	1,358,749	1,399,512	1,441,497	1,484,742	1,529,285
Total	**7,675,676**	**7,752,765**	**8,757,549**	**7,981,898**	**8,577,346**	**7,835,552**	**6,927,593**	**8,835,481**	**7,500,288**	**8,356,975**

TABLE 6-33: PREDICTED LINE RENEWAL EXPENDITURE SUMMARY FOR THE REMAINDER OF THE PLANNING PERIOD (INFLATION ADJUSTED)

6.4.4.2 Low Voltage Renewals

Table 6-34 shows the low voltage line renewal assets and planned expenditure for the current planning period. Estimate figures have been adjusted to allow for inflation. Data is displayed by Point of Supply.

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Aria 114-01		26,095								
Hangatiki	Coast 125-01			6,720							
Hangatiki	Coast 125-03										21,487
Hangatiki	Gravel Scoop 109-01						58,741				
Hangatiki	Gravel Scoop 109-10						88,112				
Hangatiki	Maihiihi 111-00					17,109					
Hangatiki	Maihiihi 111-01					42,773					
Hangatiki	Maihiihi 111-02					128,318					

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	McDonalds 110-01						17,622				
Hangatiki	Mokau 128-02				34,606						
Hangatiki	Mokau 128-05				121,120						
Hangatiki	Oparure 107-02										257,844
Hangatiki	Oparure 107-04						11,014				
Hangatiki	Otorohanga 112-01	253,354									
Hangatiki	Piopio 116-02			167,990							
Hangatiki	Rangitoto 106-01		156,573								
Hangatiki	Rangitoto 106-07		19,572								
Hangatiki	Rural 126-01				6,921						
Hangatiki	Te Kuiti South 104-01	380,031									
National Park	National Park 411-01		234,859								
National Park	Otukou 418-01				83,054						
National Park	Raurimu 410-01									72,212	
Ohakune	Tangiwai 416-02						128,497				
Ohakune	Tangiwai 416-03							37,815			
Ongarue	Manunui 408-01		137,001								
Ongarue	Manunui 408-02			33,598							
Ongarue	Manunui 408-04							37,815			
Ongarue	Matapuna 404-01				440,560						
Ongarue	Northern 402-01			268,783							
Ongarue	Ohura 413-02						176,224				
Ongarue	Southern 409-02						73,427				
Ongarue	Southern 409-03						73,427				
Ongarue	Southern 409-04						128,497				

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Ongarue	Tuhua 422-01					12,832					
Ongarue	Western 403-01								109,058		
Tokaanu	507 T 507-01		65,239								
Tokaanu	Hirangi 405-01									72,212	
Tokaanu	Kuratau 406-02						176,224				
Tokaanu	Kuratau 406-03	126,677									
Tokaanu	Rangipo / Hautu 424-01									333,779	
Whakamaru	Mangakino 118-01	158,346									
Whakamaru	Whakamaru 120-02					142,576					
	Subtotal	*918,408*	*639,339*	*477,090*	*686,261*	*343,608*	*931,784*	*75,629*	*109,058*	*478,202*	*279,331*
All Areas	Emergent	126,677	130,477	134,392	138,423	142,576	146,853	151,259	155,797	160,471	165,285
Total		**1,045,085**	**769,816**	**611,482**	**824,685**	**486,184**	**1,078,637**	**226,888**	**264,854**	**638,673**	**444,616**

TABLE 6-34: PREDICTED LOW VOLTAGE LINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (INFLATION ADJUSTED)

6.4.4.3 11 kV Line Renewals

Table 6-35 shows the 11kV line renewal assets and planned expenditure for the current planning period. Estimate figures have been adjusted to allow for inflation. Data are displayed by Point of Supply.

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Aria 114-01		286,119								
Hangatiki	Aria 114-02									127,002	
Hangatiki	Benneydale 103-01									7,735	
Hangatiki	Benneydale 103-02									15,888	
Hangatiki	Benneydale 103-03									15,651	
Hangatiki	Benneydale 103-04										646,611
Hangatiki	Benneydale 103-09	452,295	465,864								
Hangatiki	Caves 101-01				219,539						
Hangatiki	Caves 101-02				92,393						
Hangatiki	Caves 101-03				54,676						
Hangatiki	Caves 101-04				110,360						
Hangatiki	Caves 101-05				113,152						
Hangatiki	Caves 101-06				85,715						
Hangatiki	Caves 101-07				65,329						
Hangatiki	Caves 101-08				43,937						
Hangatiki	Coast 125-01			342,068							
Hangatiki	Coast 125-02								461,334		
Hangatiki	Coast 125-03										300,638
Hangatiki	Coast 125-04								280,948		
Hangatiki	Gravel Scoop 109-01							24,761			
Hangatiki	Gravel Scoop 109-02							201,961			
Hangatiki	Gravel Scoop 109-03							263,776			

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Hangatiki East 102-01						161,891				
Hangatiki	Hangatiki East 102-02						229,428				
Hangatiki	Mahoenui 113-01			269,514							
Hangatiki	Mahoenui 113-02									79,706	
Hangatiki	Maihiihi 109-09									172,512	
Hangatiki	Maihiihi 111-01					82,845					
Hangatiki	Maihiihi 111-02					89,626					
Hangatiki	Maihiihi 111-03					217,232					
Hangatiki	Maihiihi 111-04					311,743					
Hangatiki	Maihiihi 111-05						187,572				
Hangatiki	Maihiihi 111-06	249,589									
Hangatiki	Maihiihi 111-07										315,550
Hangatiki	Maihiihi 111-09									110,831	
Hangatiki	Maihiihi 111-10					111,418					
Hangatiki	Maihiihi 111-12						345,666				
Hangatiki	McDonalds 110-01						56,218				
Hangatiki	McDonalds 110-02									234,412	
Hangatiki	Mokau 128-01							780,568			
Hangatiki	Mokau 128-02				264,506						
Hangatiki	Mokau 128-03	415,397									
Hangatiki	Mokau 128-04										145,990
Hangatiki	Mokau 128-05				240,580						
Hangatiki	Mokau 128-10	311,292									
Hangatiki	Mokauiti 115-01			163,512							
Hangatiki	Mokauiti 115-02									250,267	

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Mokauiti 115-03										428,757
Hangatiki	Oparure 107-01										112,729
Hangatiki	Oparure 107-02										169,696
Hangatiki	Oparure 107-03						164,915				
Hangatiki	Oparure 107-04						437,564				
Hangatiki	Oparure 107-07						455,586				
Hangatiki	Oparure 107-08		254,718								
Hangatiki	Otorohanga 112-01	386,378									
Hangatiki	Otorohanga 112-02								92,746		
Hangatiki	Otorohanga 112-03								231,980		
Hangatiki	Otorohanga 112-04										152,479
Hangatiki	Piopio 116-01			514,207							
Hangatiki	Piopio 116-02			235,647							
Hangatiki	Piopio 116-03								105,601		
Hangatiki	Piopio 116-04						631,070				
Hangatiki	Rangitoto 106-01		197,099								
Hangatiki	Rangitoto 106-02		37,317								
Hangatiki	Rangitoto 106-04								734,596		
Hangatiki	Rangitoto 106-06									676,153	
Hangatiki	Rangitoto 106-07		339,241								
Hangatiki	Rural 126-01				98,350						
Hangatiki	Te Kuiti South 104-01	435,282									
Hangatiki	Te Kuiti South 104-02		429,866								
Hangatiki	Te Mapara 117-01			381,103							
Hangatiki	Te Mapara 117-02					278,846					

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Te Mapara 117-03							323,885			
Hangatiki	Te Mapara 117-05								311,990		
Hangatiki	Waitomo 108-01									84,696	
Hangatiki	Waitomo 108-02									218,791	
National Park	Chateau 419-01		176,405	181,697							
National Park	National Park 411-01		181,047								
National Park	National Park 411-03									445,795	
National Park	Otukou 418-01				436,995						
National Park	Raurimu 410-01									536,592	552,689
National Park	Raurimu 410-04	140,642	144,862	149,207							
Ohakune	Tangiwai 416-01						259,093				
Ohakune	Tangiwai 416-02						92,479				
Ohakune	Tangiwai 416-03							315,881			
Ohakune	Tangiwai 416-04								218,790	225,354	232,115
Ohakune	Turoa 415-01									848,383	873,834
Ohakune	Turoa 415-02										67,246
Ohakune	Turoa 415-04			127,577	114,977						
Ongarue	Hakiaha 401-02									184,914	
Ongarue	Manunui 408-01		371,998								
Ongarue	Manunui 408-02			501,200	516,236						
Ongarue	Manunui 408-03					187,076					
Ongarue	Manunui 408-04							329,617			
Ongarue	Manunui 408-05								508,461		
Ongarue	Matapuna 404-01				679,758						
Ongarue	Nihoniho 412-01								342,204		

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Ongarue	Northern 402-01			755,652							
Ongarue	Northern 402-02				762,269						
Ongarue	Northern 402-03					540,538					
Ongarue	Northern 402-04						342,110	352,373			
Ongarue	Ohura 413-01							189,596			
Ongarue	Ohura 413-02						437,992				
Ongarue	Ohura 413-06										284,069
Ongarue	Ohura 413-07	162,914									
Ongarue	Ongarue 421-01										667,239
Ongarue	Southern 409-01		416,585	429,082							
Ongarue	Southern 409-02						131,224				
Ongarue	Southern 409-03						133,209				
Ongarue	Southern 409-04						83,160				
Ongarue	Southern 409-05				432,464						
Ongarue	Southern 409-06										109,928
Ongarue	Tuhua 422-01					727,100					
Ongarue	Tuhua 422-03	149,828	154,323	158,953							
Ongarue	Western 403-01								33,808		
Ongarue	Western 403-02								675,389		

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Tokaanu	Hirangi 405-01										50,356
Tokaanu	Kuratau 406-02						362,407				
Tokaanu	Kuratau 406-03	285,753									
Tokaanu	Motuoapa 425-01										
Tokaanu	Oruatua 417-01										
Tokaanu	Rangipo / Hautu 424-01									590,789	
Tokaanu	Rangipo / Hautu 424-02						153,782				
Tokaanu	Rangipo / Hautu 424-03										195,742
Tokaanu	Tokaanu 420-01		35,932								
Tokaanu	Waihaha 426-01				13,856						
Tokaanu	Waihaha 426-02				142,557						
Tokaanu	Waihaha 426-03					485,337	499,897	514,894	530,341		
Whakamaru	Huirimu 121-01			310,720							
Whakamaru	Mangakino 118-01	435,217									
Whakamaru	Mokai 123-00							37,518			
Whakamaru	Mokai 123-01							508,015			
Whakamaru	Mokai 123-02							384,196			
Whakamaru	Mokai 123-03									489,502	
Whakamaru	Mokai 123-04							135,681			
Whakamaru	Pureora 119-02					904,399					
Whakamaru	Tihoi 124-00			12,334							
Whakamaru	Tihoi 124-01			210,207							
Whakamaru	Tirohanga 129-02										735,990
Whakamaru	Tirohanga 129-03							366,042			
Whakamaru	Whakamaru 120-01	404,883									

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Whakamaru	Whakamaru 120-02		271,393								
Whakamaru	Whakamaru 120-04					1,163,953					
Whakamaru	Whakamaru 120-05			70,725							
Whakamaru	Whakamaru 120-06						195,918				
Whakamaru	Wharepapa 122-01	280,578									
Whakamaru	Wharepapa 122-02	551,454									
Whakamaru	Wharepapa 122-03		313,545								
Whakamaru	Wharepapa 122-04		304,889								
Whakamaru	Wharepapa 122-05										394,644
Whakamaru	Wharepapa 122-06		359,406								
	Subtotal	*4,661,502*	*4,740,608*	*4,813,406*	*4,487,649*	*5,100,114*	*5,361,180*	*4,728,765*	*4,528,188*	*5,314,972*	*6,436,300*
All Areas	Emergent	799,418	823,401	848,103	873,546	899,752	926,744	954,546	983,183	1,012,678	1,043,059
Total		**5,460,920**	**5,564,008**	**5,661,508**	**5,361,195**	**5,999,866**	**6,287,924**	**5,683,311**	**5,511,371**	**6,327,650**	**7,479,359**

TABLE 6-35: PREDICTED 11KVLINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (INFLATION ADJUSTED)

6.4.4.4 33kV Line Renewals

Table 6-36 shows the 33kV line renewal assets and planned expenditure for the remainder of the current planning period. Estimate figures have been adjusted to allow for inflation.

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
GXP	**Asset Group**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Hangatiki	Gadsby / Wairere 307-01		148,547								
Hangatiki	Gadsby / Wairere 307-02				120,410						
Hangatiki	Gadsby / Wairere 307-03	328,227		348,217							
Hangatiki	Gadsby Road 305-01								385,126		
Hangatiki	Gadsby Road 305-02				323,091						
Hangatiki	Gadsby Road 305-03					79,137					
Hangatiki	Mahoenui 309-01								178,070		
Hangatiki	Mahoenui 309-02								178,070		
Hangatiki	Taharoa A 301-01			702,138							
Hangatiki	Taharoa A 301-02					356,968	183,839	189,354			
Hangatiki	Taharoa B 302-01		681,687								
Hangatiki	Taharoa B 302-02					642,540					
Hangatiki	Te Kawa Street 304-01	234,747									
Hangatiki	Waitete 306-01			294,631							
National Park	National Park / Kuratau 609-01				346,931						
National Park	National Park / Kuratau 609-02					735,805					
National Park	National Park / Kuratau 609-03			729,292							
Ongarue	Nihoniho 603-01		335,353								
Ongarue	Nihoniho 603-02	360,722									

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)											
GXP	**Asset Group**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Tokaanu	Lake Taupo 606-01										112,059
Tokaanu	Lake Taupo 606-02									101,062	
Tokaanu	Tokaanu / Kuratau 607-02				386,232						
Tokaanu	Turangi 605-01									121,310	
Whakamaru	Whakamaru 310-03				350,573						
Whakamaru	Whakamaru 310-04							534,333			
Whakamaru	Whakamaru-33 310-01			149,327							
Whakamaru	Whakamaru-33 310-02								2,015,473		
	Subtotal	*923,697*	*1,165,587*	*2,223,605*	*1,527,236*	*1,814,449*	*183,839*	*723,687*	*2,756,739*	*222,372*	*112,059*
All Areas	Emergent	245,975	253,354	260,955	268,783	276,847	285,152	293,707	302,518	311,593	320,941
Total		**1,169,671**	**1,418,941**	**2,484,559**	**1,796,019**	**2,091,296**	**468,991**	**1,017,394**	**3,059,257**	**533,965**	**433,000**

TABLE 6-36: PREDICTED 33KV LINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (INFLATION ADJUSTED)

Programmes based on 15 year cycle for 33 kV, 11 kV and LV lines. The individual asset groups making up the work pack have been reviewed and expenditure levelled since the 2009 AMP. The objective of this was to set up a smoother year-to-year cash flow programme.

Beyond 2022/23 the predicted line renewal expenditure reduces marginally due to the completion of the first 15 yearly cycle. At this time the result of the first pass are indicating that the second pass will require less work than the first pass through the assets. The first pass rectified many legacy issues and renewed some very old poor condition assets. It should be noted however that it is likely standards would have moved on by these times and that expenditure would have to be similar to present levels to meet ever increasing standards.

6.4.4.5 Line Renewal Summary without CPI

Table 6-37 provides a summary of the planned line renewal expenditure predictions for the remainder of the planning period. The figures are in current year dollars and do not include any adjustment for inflation.

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2017/18 to 2026/27)										
Description	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
LV Planned Line Renewals	769,153	519,841	376,620	525,962	255,677	673,141	53,045	74,263	316,148	179,292
LV Emergent	106,090	106,090	106,090	106,090	106,090	106,090	106,090	106,090	106,090	106,090
Total LV	**875,243**	**625,931**	**482,710**	**632,052**	**361,767**	**779,231**	**159,135**	**180,353**	**422,238**	**285,382**
11kV Planned Line Renewals	3,903,936	3,854,547	3,799,747	3,439,410	3,794,965	3,873,033	3,316,663	3,083,477	3,513,824	4,131,217
11 kV Emergent	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500
Total 11 kV	**4,573,436**	**4,524,047**	**4,469,247**	**4,108,910**	**4,464,465**	**4,542,533**	**3,986,163**	**3,752,977**	**4,183,324**	**4,800,717**
33kV Planned Line Renewals	3,903,936	3,854,547	3,799,747	3,439,410	3,794,965	3,873,033	3,316,663	3,083,477	3,513,824	4,131,217
33 kV Emergent	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500	669,500
Total 33 kV	**4,573,436**	**4,524,047**	**4,469,247**	**4,108,910**	**4,464,465**	**4,542,533**	**3,986,163**	**3,752,977**	**4,183,324**	**4,800,717**
TOTAL PREDICTED EXPENDITURE	**6,428,260**	**6,303,707**	**6,913,291**	**6,117,461**	**6,382,353**	**5,660,573**	**4,858,878**	**6,016,536**	**4,958,577**	**5,364,026**

TABLE 6-37: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE 2017/18 TO 2026/27WITHOUT CPI

6.4.5 Asset Renewal and Replacement Projects 2017/18 to 2026/27

Table 6-38 lists the Asset Renewal and Replacement projects (excluding line renewals and substations) for the remainder of the planning period (2017/18 to 2026/27) by Point of Supply. The values are in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	6k
2017/18	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2017/18	Network Equipment Renewal	Whole Network	Protection	11k
2017/18	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2017/18	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2017/18	Network Equipment Renewal	Whole Network	Relay Changes - Special	36k
2017/18	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2017/18	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2017/18	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2017/18	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2018/19	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2018/19	Network Equipment Renewal	Whole Network	Protection	11k
2018/19	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2018/19	Network Equipment Renewal	Whole Network	RADIO Specific	42k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Network Equipment Renewal	Whole Network	Relay Changes - Special	16k
2018/19	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2018/19	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2018/19	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2018/19	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2019/20	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2019/20	Network Equipment Renewal	Whole Network	Load Control	113k
2019/20	Network Equipment Renewal	Whole Network	Protection	11k
2019/20	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2019/20	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2019/20	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2019/20	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2019/20	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2019/20	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2020/21	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2020/21	Network Equipment Renewal	Whole Network	Protection	11k
2020/21	Network Equipment Renewal	Whole Network	Radio Contingency	11k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2020/21	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2020/21	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2020/21	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2020/21	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2020/21	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2021/22	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2021/22	Network Equipment Renewal	Whole Network	Protection	11k
2021/22	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2021/22	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2021/22	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2021/22	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2021/22	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2021/22	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2022/23	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2022/23	Network Equipment Renewal	Whole Network	Protection	11k
2022/23	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2022/23	Network Equipment Renewal	Whole Network	RADIO Specific	42k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2022/23	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2022/23	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2022/23	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2023/24	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2023/24	Network Equipment Renewal	Whole Network	Protection	11k
2023/24	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2023/24	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2023/24	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2023/24	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2023/24	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2023/24	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2024/25	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2024/25	Network Equipment Renewal	Whole Network	Load Control	113k
2024/25	Network Equipment Renewal	Whole Network	Protection	11k
2024/25	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2024/25	Network Equipment Renewal	Whole Network	RADIO Specific	42k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2024/25	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2024/25	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2024/25	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2024/25	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2025/26	Network Equipment Renewal	Whole Network	Have mobile generators to support loads. Upgrade existing generator.	169k
2025/26	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2025/26	Network Equipment Renewal	Whole Network	Protection	11k
2025/26	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2025/26	Network Equipment Renewal	Whole Network	RADIO Specific	42k
2025/26	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2025/26	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2025/26	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2025/26	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
2026/27	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2026/27	Network Equipment Renewal	Whole Network	Protection	11k
2026/27	Network Equipment Renewal	Whole Network	Radio Contingency	11k
2026/27	Network Equipment Renewal	Whole Network	RADIO Specific	42k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2026/27	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2026/27	Network Equipment Renewal	Whole Network	SCADA Specific	42k
2026/27	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
2026/27	Network Equipment Renewal	Whole Network	Transformer Renewals	338k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Transformers - 2 Pole Structures	Mokau	T2177 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - 2 Pole Structures	Te Kuiti South	T478 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
2017/18	Transformers - Ground Mounted	Otorohanga	T699 Rebuild to regulations and current TLC standards.	45k
2017/18	Transformers - Ground Mounted	Coast	T547 Rebuild to regulations and current TLC standards.	45k
2018/19	Transformers - 2 Pole Structures	Mahoenui	T1692 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2018/19	Transformers - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design.	45k
2018/19	Transformers - 2 Pole Structures	Mokau	T2194 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
2018/19	Transformers - Ground Mounted	Oparure	T9 Rebuild to regulations and current TLC standards.	45k
2019/20	Transformers - 2 Pole Structures	Tihoi	T1618 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
2019/20	Transformers - Ground Mounted	Mokau	T2155 Rebuild to regulations and current TLC standards.	45k
2019/20	Transformers - Ground Mounted	Mokau	T2154 Transformer upgrade.	45k
2019/20	Transformers - Ground Mounted	Mokau	T2140 Transformer upgrade.	45k
2019/20	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	45k
2019/20	Transformers - Ground Mounted	Coast	T640 Rebuild to regulations and current TLC standards.	45k
2020/21	Transformers - Ground Mounted	Te Kuiti South	T10 Rebuild to regulations and current TLC standards.	56k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2020/21	Transformers - Ground Mounted	Gravel Scoop	T1007 Rebuild to regulations and current TLC standards.	56k
2020/21	Transformers - Ground Mounted	Rural	T1390 Rebuild to regulations and current TLC standards.	45k
2021/22	Transformers - 2 Pole Structures	Caves	T1185 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2021/22	Transformers - Ground Mounted	Oparure	T1043 Rebuild to regulations and current TLC standards.	56k
2021/22	Transformers - Ground Mounted	Otorohanga	T170 Rebuild to regulations and current TLC standards.	45k
2021/22	Transformers - Ground Mounted	Rural	T1367 Rebuild to regulations and current TLC standards.	45k
2022/23	Transformers - Ground Mounted	Rural	T1559 Rebuild to regulations and current TLC standards.	45k
2022/23	Transformers - Ground Mounted	Benneydale	T2598 Rebuild to regulations and current TLC standards.	45k
2023/24	Transformers - Ground Mounted	Otorohanga	T1552 Rebuild to regulations and current TLC standards.	56k
2025/26	Transformers - Ground Mounted	Te Kuiti South	T1447 Rebuild to regulations and current TLC standards.	34k
2026/27	Transformers - Ground Mounted	Waitomo	T1003 Rebuild to regulations and current TLC standards.	45k
2026/27	Transformers - Ground Mounted	Otorohanga	T1174 Rebuild to regulations and current TLC standards.	45k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	National Park	16L02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - Ground Mounted	Chateau	16N05 Rebuild to regulations and current TLC standards.	45k
2019/20	Transformers - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transfer structure to make safer. Investigate a refurnished 33 kV / 400 v transformer. A lot of children visit this area, structure needs to be made safe.	62k
2020/21	Transformers - 2 Pole Structures	Otukou	12O01 Renew Structure. This transformer needs to be checked for loading.	39k
2021/22	Transformers - 2 Pole Structures	Raurimu	T4077 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Transformers - 2 Pole Structures	National Park	15K06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
2023/24	Transformers - Ground Mounted	Otukou	12N08 Renew with modern equivalent	45k
2023/24	Transformers - Ground Mounted	Chateau	16N04 Rebuild to regulations and current TLC standards.	28k
2024/25	Transformers - Ground Mounted	Chateau	16N06 Rebuild to regulations and current TLC standards.	51k
2024/25	Transformers - Ground Mounted	Chateau	16N07 Rebuild to regulations and current TLC standards.	51k
2026/27	Transformers - Ground Mounted	National Park	14L05 Rebuild to regulations and current TLC standards.	45k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Transformers - 2 Pole Structures	Turoa	20L31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
2018/19	Transformers - 2 Pole Structures	Turoa	20M01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	51k
2019/20	Transformers - 2 Pole Structures	Turoa	20L19 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
2025/26	Transformers - 2 Pole Structures	Tangiwai	20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	56k
2026/27	Transformers - 2 Pole Structures	Turoa	20K09 Ground mount with 100 kVA transformer.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Transformers - 2 Pole Structures	Western	08H03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - 2 Pole Structures	Ongarue	02K16 Rebuild structure 11 kV bushing are below regulation height.	56k
2017/18	Transformers - 2 Pole Structures	Ohura	07D08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2017/18	Transformers - Ground Mounted	Matapuna	01B24 Rebuild to regulations and current TLC standards.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	Hakiaha	01A31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - 2 Pole Structures	Manunui	08J07 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - 2 Pole Structures	Southern	11K11 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2018/19	Transformers - Ground Mounted	Matapuna	01A70 Rebuild to regulations and current TLC standards.	45k
2019/20	Transformers - 2 Pole Structures	Southern	10K14 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2019/20	Transformers - 2 Pole Structures	Nihoniho	06E01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2019/20	Transformers - 2 Pole Structures	Matapuna	01A75 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2019/20	Transformers - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	45k
2019/20	Transformers - 2 Pole Structures	Manunui	08J10 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
2019/20	Transformers - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	51k
2020/21	Transformers - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	49k
2020/21	Transformers - 2 Pole Structures	Southern	09K02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2020/21	Transformers - 2 Pole Structures	Ohura	07D03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2022/23	Transformers - 2 Pole Structures	Ohura	07D16 Replace with standard single pole isolating SWER structure.	39k
2022/23	Transformers - 2 Pole Structures	Southern	12K08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2022/23	Transformers - 2 Pole Structures	Ohura	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	39k
2022/23	Transformers - Ground Mounted	Northern	T4025 Rebuild to regulations and current TLC standards.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Transformers - 2 Pole Structures	Ohura	09C05 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2023/24	Transformers - Ground Mounted	Northern	07I12 Rebuild to regulations and current TLC standards.	45k
2023/24	Transformers - Ground Mounted	Matapuna	01A36 Rebuild to regulations and current TLC standards.	56k
2024/25	Transformers - 2 Pole Structures	Ohura	07D11 Rebuild structure with standard single pole isolating SWER transformer structure.	39k
2024/25	Transformers - 2 Pole Structures	Ohura	T4130 Rebuild site, two SWER transformers. On site visit needed for design. Cost split between T4130 and 10E09.	39k
2025/26	Transformers - Ground Mounted	Northern	01A48 Rebuild to regulations and current TLC standards.	56k
2025/26	Transformers - Ground Mounted	Matapuna	01B25 Rebuild to regulations and current TLC standards.	34k
2025/26	Transformers - Ground Mounted	Matapuna	01B21 Rebuild to regulations and current TLC standards.	34k
2025/26	Transformers - Ground Mounted	Matapuna	01B20 Rebuild to regulations and current TLC standards.	34k
2025/26	Transformers - Ground Mounted	Western	08I08 Rebuild to regulations and current TLC standards.	34k
2026/27	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes, cable unprotected.	45k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Transformers - Ground Mounted	Turangi	10S39 Rebuild to regulations and current TLC standards.	45k
2018/19	Transformers - Ground Mounted	Rangipo / Hautu	11S16 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Motuoapa	T4104 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Turangi	10S24 Rebuild to regulations and current TLC standards.	3k
2018/19	Transformers - Ground Mounted	Kuratau	08R22 Rebuild to regulations and current TLC standards.	3k
2020/21	Transformers - 2 Pole Structures	Waihaha	04Q06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
2020/21	Transformers - 2 Pole Structures	Oruatua	09U12 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Transformers - 2 Pole Structures	Kuratau	09R28 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
2022/23	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Rebuild to regulations and current TLC standards.	45k
2024/25	Transformers - Ground Mounted	Turangi	10S30 Rebuild to regulations and current TLC standards.	41k
2024/25	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Rebuild to regulations and current TLC standards.	34k
2026/27	Transformers - Ground Mounted	Tokaanu	10R20 Rebuild to regulations and current TLC standards.	45k

TABLE 6-38: SUMMARY ASSET RENEWAL AND REPLACEMENT PROJECTS (EXCLUDING LINE RENEWALS AND SUBSTATIONS) PLANNED FOR 2017/18 TO 2026/27 BY POINT OF SUPPLY (WITHOUT INFLATION)

Section 7

7. Risk Management

TLC uses formal and informal studies based on industry experience and information to identify any risks. Risk management is a continual improvement process that encompasses many things including assets, health and safety, the community, operations, public hazard control, natural events and other infrastructure.

Most of TLC's business processes and activities have some element of risk management. A key driver for this business approach is the company's corporate objective of delivering a strong sustainable network to the greater King Country. A high risk approach to business activities may not achieve this. The AMP, Annual Plans and SMS are documents that manage risk. These plans and other inputs are used to manage the network in such a way that continually focuses on the identification of hazards and their control (elimination, isolation or minimisation).

7.1 Risk Policies

7.1.1 Corporate Risk Policies

TLC has a structure of policies and standards that are used to manage corporate risk. A subset of these is distribution-related policies and standards as is the SMS. These policies and standards include direct risk lowering policies and others that are closely related. The SMS focuses on all network assets with a view to controlling hazards to the public and property such that the risks of serious harm or significant damage are deduced to a tolerable level.

Policies and standards are reviewed regularly and there is a formal process in place to ensure this. The process involves new policies and standards being considered, approved, and reviewed by an executive committee. The SMS has its own review and audit policies and procedures. The structure of this process is illustrated in Figure 7.1.

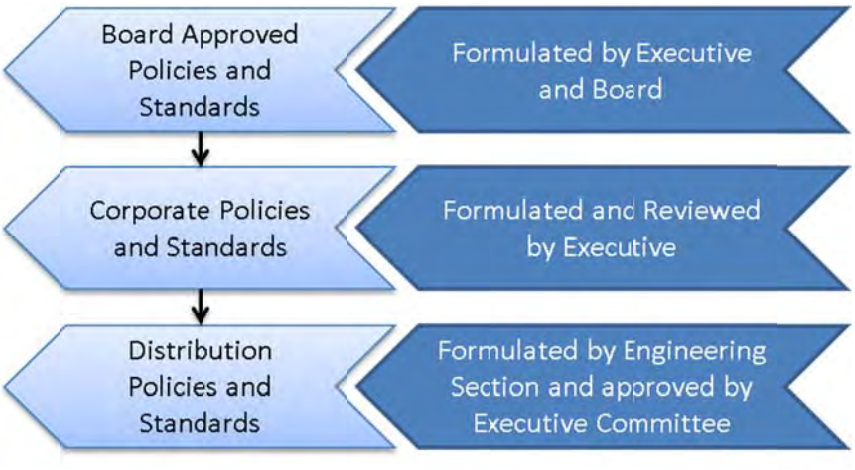


FIGURE 7.1: STRUCTURE OF CORPORATE POLICIES AND STANDARDS

The methods used to assess corporate risk issues include:

- Previous events.
- Legislation and Regulation.
- Financial security.
- Strategic requirements.
- Network performance analysis.
- The cost and implications of not controlling risks.
- Public hazards are mitigated via the SMS.

The details that corporate risk policies cover include hazard control, compliance, financial, strategic, human resources, and events.

Risk analysis and its considerations are fundamental to business and corporate strategy to provide customers with a network that produces a reliable, adequate quality and hazard controlled service at an affordable price.

7.1.2 Distribution Asset Risk Policies

The asset risk policies are mostly placed within the Distribution Policies and Standards as illustrated in figure 7.1. The details of asset risk policies are included in distribution standard codes, policies and other documents, which include:

- Emergency management procedures.
- Civil defence policies.
- Hazard control policies and procedures.
- Design standards.
- Construction and material standards.
- Operating standards and procedures.
- Specific instructions.
- Distribution code.
- The Asset Management Plan.
- The Safety Management System.
- Individual project specifications and standards.
- Insurance for equipment other than overhead lines related hardware.

These policies consider the probability of an event and its consequences. These include:

- Physical failure risks.
- Operational risks.
- Natural environmental events.
- Factors outside of the organisation's control.
- Stakeholder risks.
- Risk associated with the different life cycle phases of assets.
- Public related hazard control.

TLC policies recognise that risk is defined as the product of probability and consequences. For example, as described in Section 5, planning criteria and assumptions are based on this recognition.

The policies include various techniques for identifying, quantifying and managing asset related risks with varying levels of complexity. TLC is constantly reviewing its individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategies.

TLC uses the understandings gained from risk assessments and the performance of risk control strategies to provide input into:

- Asset management strategy and objectives.
- Long and short term asset management and business plans.
- Identification of adequate resources.
- Training and competency needs.
- Controls for asset life cycle activities and the implementation of this plan and annual plan subsets.

A key strategic tool for the implementation of the asset management process is the Basix information system. This allows performance to be measured, and forms the foundation for on-going risk assessment and prioritising projects for risk.

7.2 Risk Assessment and Analysis

7.2.1 Corporate Risk

Table 7.1 summarises the corporate risk assessment and mitigation.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
HAZARD CONTROL	
Events that may cause harm to staff, public, and property.	Methods: Identify potential and existing hazards associated with network operation, staff, public and other stakeholders. Place importance on hazard free designs. A safety management system in compliance with the Electricity (Safety) Regulations 2010 has been in operation from 1st September 2011. This document is referenced to the AMP and it will become an increasingly integrated document to identify hazards to the public, assess them for risk and apply controls to significant hazards. Various workplace hazard control mechanisms are in place to ensure compliance with HSE legislation. Methods for control include various policies, procedures and on-going programmes. High level corporate risk is managed by having a strategic plan that addresses various environmental risks and develops a high level plan to control the risk. Details: Corporate strategy documents that are designed to provide direction and thus reduce the risk of doing business include, by controlling hazards: • Strategic Review. • Statement of Corporate Intent. • Annual Strategic and Business Plans for each section of the company. • HSE policies procedures and plans. • Safety Management System development and compliance. • A SWOT analysis is often used when these plans are being formulated. • Insurance. Various criteria are used when this analysis is carried out at a high level. These include factors such as: • Previous work and plans. • The environment. • Customer service. • Asset needs. • Other factors. From an asset needs perspective, risk consideration includes: • Physical failure risk. • Natural environmental risks. • Factors outside the organisation's control. • Stakeholder risks. • Risks associated with different life cycle phases of assets. Conclusion: The objective is to be aware of hazard related risks and have plans in place to control hazards to a level that is acceptable to all stakeholders. The risk of not having these in place will have detrimental effects on people, equipment, customer service and organisational profitability/sustainability. (Businesses that cannot control hazards to adequate levels become unsustainable.)

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Human Error.	Methods: Policies, training and, as a backstop, insurance. Details: On-going training, assessment and monitoring to ensure staff are competent to complete the tasks in front of them. On-going review of policies and follow up after reported incidents. Conclusions: It is a corporate objective to have a well trained and competent work force. As a backstop to reduce stakeholder risk, insurance is in place.
COMPLIANCE	
Threat of prosecution and extensive investigation.	Methods: Include objectives and strategies at all levels of operations (various plans including AMP, disclosures, policies) to comply. Details: Various policies, work activities plans and documents to comply with legislation and regulations, including HSE, Finance, Commerce Commission, Tax, Technical, Pricing, Industry, Human Resources, Electricity Act/regulations and Others. Conclusion: Business objectives that comply with acts and regulations that avoid costly investigations and prosecutions by enforcing authorities.
FINANCIAL	
Events that restrict the organisation's ability to generate income to finance operations and capital investment.	Methods: Carefully analyse revenue risks and implement strategies to minimise these. Details: Dry year energy savings and future environmental concerns driving new technologies put energy based revenue streams at risk. TLC decided to move away from energy based billing income streams to create a more environmentally focused asset capacity and demand based method of charging. Conclusion: Asset capacity and demand based billing introduced in 2006/07.
Remote rural lines that were built with government subsidy need renewing. The government is not providing any subsidy for renewal.	Methods: The impact was calculated and politicians and officials were lobbied. Strategies put in place to manage rural lines such as ensuring capacity requirements do not increase and require upgrades as well as renewals. Details: Results in cross subsidy from urban areas to rural areas. TLC has informed stakeholders of these consequences. Conclusion: Politicians and officials have no solution to this problem. TLC will implement renewal strategies to keep these costs minimised, extend programmes as far as possible and to maximise renewal efficiency and to reduce cross subsidisation.
Customers' ability to pay.	Methods: Close monitoring and extensive discussions with customers. This includes comparing rates with other network companies. Details: Use of focus groups, customer clinics, consultation and stakeholder feedback to monitor the issue. On-going meetings and discussions on reliability, renewal and hazard control issues. Models have been set up to compare rates with other network companies. These models also give TLC an understanding of the levels of cross subsidisation that results with volumetric based charges. Conclusion: The TLC area is low income as indicated via various national studies. TLC has to be very mindful of customers' ability to pay and the charges relative to other network companies.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Fraud	Methods: Checking of payment systems. Use of insurance as backstop. Details: All payments are checked by executives from different sections. Various policies and levels of authorisation of accounts for payment are in place. Auditing to ensure items exist and that they have been purchased for realistic prices takes place. Quotes and estimates have to align to annual plan. Reconciliation of annual plan to payments. Insurance in place as a "backstop". Conclusion: Auditing and checks are in place.
STRATEGIC	
The organisation continuing to develop activities that ensure customers' expectations are satisfied.	Methods: Asset management systems tailored for the network. Structure to maximise renewal efficiency. Reliability and quality of supply that customers want. The organisation will develop advanced network technologies. Details: AMP produced that contains comprehensive details. Plan reviewed annually and updated based on feedback from customers and changes to the operating environment. Conclusion: One of the purposes of the AMP document is to mitigate the risk of having a network that does not perform to expectations. Initiatives for an advanced network are included in the AMP.
ENVIRONMENTAL	
Environmental issues will influence many of the future national and international governance requirements. The organisation needs to recognise this and minimise the risk looking forward into the future.	Methods: Strategic and operational decisions need to consider the long term environmental issues. Details: Corporate strategies and policies that consider the environmental impact. For example minimising SF6 gas, demand billing to promote demand side management of active and reactive power, billing structures to promote distributed generation, end of life disposal considerations with all assets, and investment in distributed generation. Reviews of compliance with resource management legislation. Conclusion: TLC is looking to the future and considering all aspects of its operation. This will include the development of advanced network technology.
HUMAN RESOURCES	
Loss of skills with intellectual knowledge leaving the organisation. (Network and local)	Methods: Creating a good working environment with competitive remuneration. Details: Focus on developing local people and providing them with the skills to meet company's and customers' needs. Conclusion: TLC recognises the importance of retention of staff members who have the intellectual knowledge to maintain and operate the network in a sustainable fashion.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
CUSTOMER RELATIONS	
Poor customer relations over direct and demand based billing	Methods: Various customer campaigns and other customer service plans/programmes/initiatives. Pricing has also been reviewed by an independent body. Establishment of a communications section. Details: Initiatives include: • Call centre staffed by local people. • Training programmes for call centre staff. • Focus group meetings. • Customer Clinics. • Other public relations programmes. • Independent review of pricing and the way demand levels are charged. Conclusion: Managing the risk of adverse public relations is important to the organisation.
DISTRIBUTED GENERATION	
Distributed Generation Applications	Methods: Demand billing to reduce the risk of volume changes. Researched lists of engineering issues that need considering when completing distributed generation analysis. Details: Volume charges reduce the incentives for lines companies to connect generation. Demand billing overcomes this. TLC has a list of about 25 conditions that need consideration before intermediate and large distributed generation plant can be connected. Generators are made aware of these and asked to have consultants work through each of these and submit solutions with the final applications. Distributed generators often choose not to do this and want TLC to take on the risks of connection. TLC resists this as it is well aware of the damage unstable distributed generation can cause on the network. Distributed generators' investors can then complain to the Electricity Authority and these complaints can add considerable legal costs to the organisation's operation. Conclusion: The connection of distributed generators to a network that was originally designed to carry energy from a central point out to customers can add considerable costs and complexities. The Electricity (Distributed Generation) Regulations add to this complexity (now the participation code).

TABLE 7.1: CORPORATE RISK ASSESSMENT AND ANALYSIS

TLC has insurance to mitigate corporate risk should incidents occur.

7.3 Network Risk

7.3.1 Overhead Lines

Table 7.2 summarises the overhead line risk assessment and mitigation:

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
PHYSICAL FAILURE RISKS	
Vegetation	Methods: About 50% of faults in rural areas originate from some form of tree issue. As a consequence of this TLC has established, and will continue, a comprehensive vegetation control programme. Details: The programme consists of planned patrols and follow ups and emergent activities as detailed in this Plan. Conclusion: Vegetation is one of the key spokes in the wheel of mitigating risks with overhead lines. Related issues include hazard control, reliability, public hazard control and quality. For example, trees falling through lines often cause voltage spikes, which then destroy appliances.
Aged Equipment	Methods: Renewal programmes, patrols, follow ups after faults and auto recloses, customer and staff reports, inspections, observations, outage data, performance monitoring, and the intellectual property of experienced staff are all methods used to mitigate risk with aged overhead lines. Details: The various policies, strategies, processes and plans detailed in this Plan. Conclusion: Mitigating old overhead lines risk forms a large part of this Plan.
Line clashing	Methods: Fault investigation to identify possible causes. Line design review when problem areas are identified. Details: When line clashing is suspected, all upstream fault current recording devices are downloaded and reconciled to runs of TLC's network analysis programs to try and identify the location. Once the expected location is identified a site patrol is carried out to pin point the exact location. Once the problem area is identified, designs are completed to remove the problem. Conclusion: Line clashing is caused by birds, fault currents, wind and flying tree branches can cause conductor burn down and consequential risk issues such as forest fires. Line clashing also reduces the effectiveness of protection schemes and is an important risk to mitigate.
Lines around boat ramps	Methods: Line inspections include recording of overhead line heights above ground to ensure they comply with Regulations. Signs are also put in place. Details: Boat masts coming into contact with overhead lines is a problem around the shores of Lake Taupo. Line heights have been found to comply, but this is still a problem when boat operators forget to lower their masts. Warning signage is in place and is being monitored to ensure it is maintained. Monitoring of this signage is part of line patrols and inspections. Conclusion: Line clashing caused by boat is difficult to guard against. More signage is planned to help mitigate the risk.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Theft of copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority on the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of components of these systems leads to risks.
OPERATIONAL RISKS	
Capacity	Methods: Asset and engineering staff monitor field equipment loadings and annually work through the entire network examining data and reconciling these to network models. Some equipment also has alarms set at certain load points. Protection systems are in place. Details: Models are reconciled to field data and run. All equipment ratings and their operation are considered. (This is an annual exercise, in addition to the daily use of models to check specific needs such as customer requests for load and motor starting etc.) This repeated modelling gives regular on-going monitoring of network loads. Conclusion: Accurate, up-to-date and regularly used network models by all levels of technical staff are the principal tools for mitigating the risk of overloading network equipment. Priority is placed on ensuring protection systems are operational.
Hazard Control	Methods: The renewal programmes, patrols, follow-ups after faults, auto recloses, customer and staff reports, inspections, priority setting, observations, outage data, performance monitoring, and the intellectual property of experienced staff are all methods used to mitigate hazards with aged overhead lines. Protection systems are set up in compliance with legislation and industry practice. SMS and accreditation of this to a standard. Details: The various policies, strategies, processes and plans described in this Plan. A major focus of daily activities is to control hazards including both work and public related. Protection systems that are effective, simple and reliable are implemented. The protection systems are tested, monitored and renewed as detailed in this Plan. The network analysis model has a protection sequencing model and this is used to ensure protection is operating in the correct fashion to minimise the impacts of faults on overhead lines. Conclusion: Mitigating the hazards associated with old overhead lines risk forms a large part of this Plan.
Fault Currents	Methods: The effects of fault currents on overhead lines are considered by modelling fault current levels and checking these throughout the network. Details: Levels are looked at regularly and reconciled to line strength and spacing. (Experience has shown that fault levels above 100MVA on standard 11 kV light construction will cause problems.) Control of fault current levels is one of the reasons why the modular substation concept was developed, i.e. smaller modular zone substations designed to limit fault currents. Conclusion: Mitigating the hazards caused by fault currents has been included in this plan.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Private Lines Connected to TLC Lines	Methods: Inform line owners of hazards observed on their lines when patrols and inspections are taking place. Details: Line owners are written to when hazards are observed. Fuses are placed at the point of connection to minimise the risk of these lines affecting other customers. Conclusion: Privately owned lines are now better covered by the Electricity (Safety) Regulations, but to date there has been no indication as to how Energy Safety intends to police the obligations.
NATURAL ENVIRONMENTAL EVENTS	
Slips	Methods: Potential slips are identified during patrols, 15 yearly inspections or other reports. Details: Plans completed and lines/poles moved as required. Conclusion: Slips regularly occur in the rugged King Country and inspection/patrol staff have to be vigilant to observe ground cracks and potential slip sites.
Wind	Methods: 15 year renewal programme, patrols and other reports. Details: Line design programme used to ensure line strengths are adequate when renewal and patrol data analysed. Conclusion: Many of TLC's older lines are under strength (see section 3) and the renewal programme is gradually increasing line strengths. (Depends on importance of each line and its location as to how much strength is increased during each pass.)
Flooding	Methods: Poles and other equipment likely to be washed out or affected by floods identified as part of 15 year programme. Details: Major issues resolved as part of 15 year programme. Conclusion: Pole washouts and difficulties accessing key equipment are the greatest flood risks.
Seismic	Methods: Construction standards used to ensure the impact of seismic events on pole loadings are considered. Details: Line design calculations include seismic considerations. Conclusion: Many of the older sections of the network have inadequate seismic strength.
Lahar	Methods: Lahar paths are identified by 15 year inspections, patrols and other special events. Details: Lines are kept out of Lahar paths or, where this is not practical, protection is put in place. Conclusion: TLC had protected poles prior to the 2007 Mt. Ruapehu event. Lahars are a consideration when lines are being designed.
Geothermal	Methods: Geothermal areas are normally unstable and overhead lines are kept away from these areas as far as practical. They are often associated with sensitive Maori land. Details: Geothermal areas are identified by steam coming out of the ground. Often overhead lines have to be used through these areas as an alternative to cabling. Conclusion: TLC has to be aware of geothermal activity.
Volcanic	Methods: TLC has several active volcanoes in the network area. The potential of ash contamination has to be considered when selecting insulators and positioning equipment. Details: The size of insulators used in the network generally has been increased to improve performance when subject to ash and fertiliser. Conclusion: A number of lines have the potential to be affected by ash and volcanic activity.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Snow, ice and other storm hazards	Methods: Renewal programmes that take into account likely snow and ice loadings when line designs are reviewed. Details: Existing and proposed designs are checked with a line design computer programme before work is issued. Conclusion: Many of TLC's existing lines are under present code strength requirements. Renewal programmes are addressing these in a staged way. The strength of existing assets means that it is not possible to do this in the first 15 yearly cycle unless more funding is available. The more important lines have more work completed on the first cycle. The more remote lines with fewer customers will have the most likely points of failure, or most significant consequence sections strengthened. For example, attention is given to long river crossing spans, etc.
Natural Hazards with greater intensity than can normally be expected	Methods: Natural events with intensity greater than design standards do occur. The local environment is considered when lines are being designed or inspected prior to renewal. Details: Lines inspectors and designers are involved with fault analysis after natural events and outage records. Engineering staff have also built up knowledge on natural events and consider the specific environments when completing designs. Conclusion: Care is taken to minimise the risk of natural events. It is not possible to eliminate all possible events as costs would be prohibitive.
STAKEHOLDER RISK	
Extensive destruction of overhead lines	Methods: Renewal programmes included in this AMP need to be completed to manage risk. Overhead lines are not insured. Details: Patrol and inspection programmes as detailed in the AMP. Conclusion: The steps for controlling hazards detailed in this plan are designed to manage shareholder risk.
Fire started by overhead lines	Methods: Renewal and maintenance programmes included in the AMP. Protection systems set up in accordance with industry practice. Details: Renewal to reduce the likelihood of failure is included in the AMP. (Failure can lead to fires being started). Vegetation control programme helps reduce the risk of fire. TLC works with forest owners where practical to advise them of this risk. TLC uses corona camera inspections as detailed in Section 6 to reduce the risk of fire due to tracking insulators. Protection systems in place that are effective and isolate faulty lines. Public Liability insurance is in place as a backstop. Conclusion: Forest and grassland fire is a major risk to stakeholders as is the cost of putting the fires out. (This cost is passed onto TLC by the rural fire authority).
Age of TLC overhead lines assets	Methods: Age of assets recognised in the plan and strategies put in place to control these. Details: Patrol and renewal inspections and the corrective actions that come out of these plans is the base for renewals. Conclusion: Have a long term plan to change out overhead assets before they reach the end of their lifecycle and fail.
Supply quality components into the network as part of the renewal programme	Methods: Have clear quality standards for components and checking of items to ensure they meet these standards. Details: Constantly reviewing, updating, standards, monitoring and auditing performance of components to ensure they will meet lifecycle expectations. Conclusion: Component quality is vital to minimise the risks associated with different lifecycle phases of assets. Early failure will cause costs and customer disruption.

TABLE 7.2: IDENTIFIED RISKS AND MITIGATION OF RISKS TO OVERHEAD LINES

7.3.2 Zone Substations and Voltage Regulation Equipment

Table 7.3 summarises the zone substation and voltage regulation risk assessment and mitigation.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
PHYSICAL FAILURE RISKS	
Aged Equipment	Methods: Inspection, maintenance and renewal programmes are in place. Details: TLC is keeping a close watch on its aged transformers and switchgear. Regular oil tests are completed. Emergency alternatives are being put in place for aged switchgear, both for maintenance work and in case they fail. The Plan includes a programme for refurbishing aged zone substation transformers that have high winding water content. Conclusion: The risk of aged equipment failing in zone substations is being mitigated by this Plan.
Electronic Equipment and Software	Methods: Today's substation equipment, including voltage regulators, is driven by software. It is important that systems are in place to both manage equipment settings and the software itself. TLC's maintenance plan requires annual downloading of equipment settings and the reconciling of these to master files. Details: In addition to regular downloads and reconciliation, TLC, as far as practical, sources equipment that has similar software for both protection and voltage regulators. In addition, the master file settings are also reconciled with the network analysis program. Conclusion: TLC's technical staff are very mindful of the need to carefully manage various control and protection packages, and to have these backed up for disaster recovery.
Security	Methods: Security is enhanced by improving fences, gates and increasing the number of locking devices. Security is also an important design consideration. Details: This Plan includes a number of security improvements at zone substations. Security has been improved in future designs by using low cost methods such as locating equipment in shipping containers, and similar enclosures with relatively high security. Designs are also increasingly focused on ensuring that security risks are reduced. Conclusion: TLC has recognised that a number of its legacy sites lack the level of security expected with infrastructure in today's environment, and improvements are being made.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and their property, i.e. livestock. This risk is reduced with a programme of substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority on the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems may lead to risks for staff and the public.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
OPERATIONAL RISK	
Hazard Control	Methods: TLC has recognised that many of its legacy substations have hazard control needs and much of the expenditure in this plan is associated with addressing these. Hazard control is a priority consideration for new designs. Details: Much of the expenditure is focused on making it more difficult for staff, and the public, to get into hazardous situations while working on, or being in close proximity to, substations. TLC is looking beyond this and is using its network analysis program to calculate arc flash and fault current levels. These quantities are carefully considered in new designs and operating criteria. Conclusion: Hazard control and minimising/eliminating risks of incident/accident and harm, is one of the main focuses of this Plan.
Capacity	Methods: The load on zone substation equipment is being monitored. These loads are reconciled to data models, which are regularly run (daily) for many reasons. The existing network is modelled, as is any future load predictions, when alternative supplies are configured. An annual detailed review takes place. Details: Loading data are used to check capacity constraints. The models are set up to assist with identifying equipment that is operating beyond capacity limits. Conclusion: TLC's on-going network analysis and data collection is focused on utilising asset capacity without exceeding ratings. This work mitigates the risk of TLC operating equipment beyond ratings.
Substations supplying areas with no alternative. Supplies via single bus bars with no emergency or alternative supply option	Methods: Various methods are included in this plan to put in place some form of alternative light load supply. Details: Alternatives are being developed with the deployment of modular substations and adding additional modular switchgear. Conclusion: There are risks of extended outages in a number of areas that would be unacceptable to customers.
Environmental risks associated with operational issues	Methods: A number of TLC's legacy substations do have environmental risks mostly associated with lack of automatic oil separation control. These are being addressed in this plan. Present and future designs consider environmental issues. Design and equipment selection also considers end of life disposal. Details: This Plan and the engineering approaches taken by TLC with zone substations and voltage regulators focus on protecting the environment. For example, TLC's modular substation does not include tanked tap changers that often have oil leaks after covers are removed for maintenance. Modular substations and equipment shelters include integral oil containment and site environmental control systems. Conclusion: TLC is addressing legacy environmental issues and is finding innovative ways to address future environmental issues at the lowest possible cost.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
NATURAL RISK ENVIRONMENTAL EVENTS	
Wind, Snow, Ice and other storm hazards	Methods: Zone substations and regulator sites are designed and positioned to withstand expected winds, snow, ice, etc. Vegetation around zone substations is controlled. Details: Zone substations and regulator sites have been assessed for their ability to withstand storms etc. Conclusion: Where shortfalls have been identified these have been included in this Plan, e.g. protection and switchgear improvements.
Flooding	Methods: Zone substations and regulator sites in flood prone areas have been identified. Details: The Plan includes proposals for alternative supplies for substations that are in flood prone areas. Conclusion: Flooding is a low probability, high impact risk that has been considered and mitigated against in this Plan, e.g. Taumarunui north.
Lahar, Geothermal	Methods: Locations of zone substations have been evaluated for potential Lahar and geothermal risk. Details and Conclusion: Zone substations are not located in Lahar paths or geothermal areas.
Volcanic	Methods: Locations of Zone substations have been evaluated for risk due to volcanic activity. Details: Three substations are likely to be affected by volcanic activity on the central plateau. Two of these substations are capable of backing one another up. It is not economic to be able to back up the third. The plan does include additional automation to be able to transfer the 33 kV supply to this third site by alternative lines. The Plan includes improvements to several sites that will increase resistance to volcanic eruptions. Conclusion: Volcanic effect on zone substations is a low probability, high consequence event that has been considered and mitigated in putting together the programmes in the AMP.
Seismic	Methods: Zone substation transformers and the effects of seismic activity have been assessed. Buildings have not at this time. Details: Most sites have seismic security. Security for the remaining sites has been included in the plan. Where buildings pose a risk, an alternative switchgear installation has been included in the Plan. These installations are often housed in containers. Conclusion: Earthquake effects on zone substations are a relatively certain, but infrequent event, and have been considered and mitigated against in putting together the programmes in the AMP. Note: At the time of writing, we have reviewed the Plan after giving consideration to the effects of the Canterbury earthquakes and intend to continue the strategies included in earlier AMPs. Based on the information that has come available to date, we believe TLC's Plan will address the needs adequately.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
FACTORS OUTSIDE OF THE ORGANISATION CONTROL	
Network events that are more severe than Standards and Codes	Methods: When it is obvious that a risk exists that exceeds the design requirements listed in codes, additional engineering is applied. Details: Designers are aware of local issues and these are included in the design process. Conclusion: TLC designs have to consider local issues. At the end of the day, however, it is difficult to include every issue that may or may not happen and build economic outcomes to cover off potential eventualities. The calls are made based on professional intellectual learning with partial insurance as a risk backstop.
STAKEHOLDER RISKS	
TLC's demand billing system failing	Methods: The demand billing system is important in controlling the demand growth and the loadings on zone substations and voltage regulators. If growth is higher than predicted, network strengthening will be required at a level greater than that included in this plan. Details: TLC is developing and reviewing the demand billing processes constantly to ensure its success. This includes: Reviewing/developing the integration with the AMP. Reviewing customer feedback. Reviewing the success of its ability to control demand growth. Altering load control strategies. Modifying and tuning all of the above. Conclusion: TLC is committed to developing its demand based billing and integrating it into its overall asset management strategy.
Major failure of sub-transmission or zone substation resulting in an extended outage.	Methods: TLC is increasing diversification as detailed in this Plan to minimise this risk. Details: The existing sites are being developed to ensure reliance is not placed on any one piece of equipment. Additional modular units are being used to reduce the dependence on any one piece of equipment. Conclusion: Risk is being reduced through diversification at the lowest possible cost.
RISK ASSOCIATED WITH DIFFERENT LIFECYCLE PHASES OF ASSETS	
Equipment failing early in lifecycle	Methods: Quality standards and contingencies are in place to cover early failure. Details: Quality specifications are prepared and work is audited against these specifications. Contingencies include planning for initial problems in the early part of equipment lifecycle "bathtub reliability curve". Conclusion: Quality standards are important, along with recognising the reality is that failures may occur in the initial part of an equipment lifecycle.
Equipment failing when it is run beyond lifecycle	Methods: Renewal programmes are in place and there are contingencies for equipment that is run beyond its lifecycle. Details: Renewal programmes are targeting equipment that is no longer fit for purpose. If equipment is fit for purpose, contingencies need to be in place in case the equipment fails. The Plan has been prepared on this basis. Conclusion: Some items within the TLC network are old. Failures from time to time are an expectation and a risk that has to be lived with given that resources, both financial and staff, are not available to renew much of this old equipment in a short time.

TABLE 7.3: IDENTIFIED RISKS AND MITIGATION OF RISK TO ZONE SUBSTATIONS AND VOLTAGE CONTROL EQUIPMENT

Note: Equipment insurance policies with excesses in the $20k to $30k range are in place for substation equipment.

7.3.3 Distribution Substations, Switchgear and Underground Systems

Table 7.4 summarises distribution substations, switchgear and underground systems risk assessment and mitigation.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
PHYSICAL FAILURE RISKS	
Earthing Systems, particularly SWER systems causing earth potential rise	Methods: Design and test earthing systems including considering the effects of fault currents. Details: Bi-annual testing of isolating SWER transformers, and a 15 year programme for other transformers. Use of TLC's earth design module network analysis to correctly design the initial work and any improvements. Conclusion: The risk associated with earthing systems is recognised and being mitigated as part of this Plan.
Loss of Circuit Breaker Electronic Setting Data	Methods: The importance of equipment data settings and firmware is recognised. Details: An annual dump of data occurs as part of maintenance programmes. These are reconciled to originals and copies are kept off site. Conclusion: The loss of recloser, and other distributed software and equipment settings, is recognised and the risks are mitigated.
Security of equipment not being up to standard with potential for unauthorised public access.	Methods: Initially, and on an on-going basis, check and upgrade security. SMS reporting. Details: All service boxes are inspected to ensure security is up to current TLC standards, and maintained or renewed if found insecure. All ground mounted equipment has been inspected and is progressively being maintained with an increased number of locking devices. All new equipment must have all terminals insulated at ground level. All existing equipment has been surveyed and renewals included in programmes. Conclusion: Unauthorised entry to equipment is a credible, but low probability/high impact risk. Note: Securing against unauthorised access is a key focus of the Safety Management System that is being implemented as part of the requirements of the Electricity (Safety) Regulations 2010.
Legacy underground systems that have been constructed using low cost methods and often using unskilled labour	Methods: Renewal programmes are in place to identify and implement hazard controls. Details: A renewal design review process is used to develop prioritised solutions. Conclusion: TLC is identifying and managing this risk. It will take a number of years to remove the risk of, for example, civil contractors making contact with a shallow, buried, unmarked, and unprotected cable.
Other equipment failures such as distribution transformers and related equipment	Methods: Renewal programmes in place that considers known equipment failure modes. Contingencies in place in case of failures. Details: The history of previous failures and the types of events that will likely occur are included in renewal programmes. Emergency spares such as distribution transformers are kept in stock. Engineering is done in such a way to minimise the risk of failure. For example, lightning arrestors are placed on each transformer; attention to detail is given to the quality of materials and workmanship, (cable jointing, types of insulators, fuses, switchgear, etc.). Conclusion: Contingencies for equipment failures is part of TLC's planning processes.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
OPERATIONAL RISK	
Capacity	Methods: Equipment loadings monitored. Network analysis package used. Details: MDIs fitted to ground mounted equipment and read annually. Data from various recording devices analysed to ensure equipment has capacity. Load flow and fault current packages regularly used to make sure equipment is operating within ratings. Conclusion: The risk of equipment being required to operate beyond its ratings is closely monitored.
Protection systems operating incorrectly	Methods: The set up and performance of protection systems associated with distribution switchgear is closely monitored. Details: Protection systems set up with care using computer programmes. Performance of equipment monitored for operation after each event. Priority placed on changing batteries and servicing/renewing other equipment that causes protection equipment to operate incorrectly. Attention given to fault currents and clashing effects in addition to other co-ordination difficulties. Conclusion: Protection systems operating incorrectly add to risk of harm and damage. Incorrect protection operation is a low probability high impact risk. The risk is minimised by monitoring and regular modelling.
Contractors digging up underground cables	Methods: Detailed as built drawings and auditing processes in place to ensure records are correct. Competitive cable location service. Details: TLC audits cable installs to ensure they are completed to specification and drawings. Care is taken to ensure all variations are correctly recorded. Several contractors are available to do cable locations, which results in excavation contractors being able to get competitive quotes. Conclusion As built and audits are checked and filed. Cable locations and good records minimise the risk of underground cables being damaged.
Loss of skill to set up and maintain Electronic Protection and Circuit Breakers	Methods: On-going training of staff, either in-house or external courses. Details: Systems in place to identify needs and schedule training. The importance of ensuring staff with the intellectual knowledge are retained is recognised. Conclusion: Protection systems built into distribution equipment switchgear have become more complex in recent years. Systems have to be in place to manage this complexity.
NATURAL RISK – ENVIRONMENTAL EVENTS	
Seismic	Methods: Designs to include seismic requirements. Details: Care is taken to mount transformers and switchgear on poles of suitable strength. TLC uses a design package that includes a seismic calculator when reviewing existing designs as part of the renewal programmes and also for future designs. A preferred option for laying cables is to place them in ducts. Conclusion: TLC considers seismic risk as part of its renewal and new construction design practices. It mitigates this risk.
Flooding	Methods: Underground equipment is, where possible, located away from flooding areas. Details: Where equipment is located in areas that may flood waterproof and sealed equipment is used as far as practical. Conclusion: Flooding risk is considered and mitigated as far as practical.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
Wind, Snow, Ice and other System Hazards	Methods: Distribution substations, switchgear, and underground systems are designed to withstand storms in compliance with the various industry Codes of Practice and the needs of the King Country environment. Details and Conclusion: Local knowledge and TLC's design package, which contributes to codes, are used to mitigate this risk.
Lahar, Geothermal and Volcanic	Methods: Lahar, geothermal and volcanic areas have been identified. Details: Distribution substations, switchgear and underground systems are not located in Lahar paths or geothermal areas. Conclusion: Where possible, risks are mitigated. Given that a number of New Zealand's active volcanoes are in the middle of the network area it is not possible to totally mitigate volcanic effects.
FACTORS OUTSIDE OF THE ORGANISATION'S CONTROL	
Natural events that are more severe than expected	Methods: Have emergency procedures in place to help minimise the effects. Use available intellectual knowledge to include designs to minimise the effects. Details: TLC has emergency event handling procedures in place. Local knowledge is used to vary designs to minimise the effects of severe events. Conclusion: Unexpected events will happen. It is not possible, practical and economic to eliminate this risk.
Traffic accidents and other damage	Methods: Have emergency procedures in place to help minimise the effects. Have emergency stocks of materials. Designs that reduce the risks. Details: TLC has emergency event handling procedures and holds minimum stock levels. Conclusion: Unexpected events happen. The severity has to be controlled by emergency procedures.
Public access to Pillar boxes in areas where power is underground	Methods: Have a planned inspection programme to inspect and record pillar box conditions. Details: TLC replaces approximately 50 service boxes per year. The new boxes are labelled and securely fastened with padlocks and security screws. Conclusion: Unauthorised access is minimised by the use of security locking and pillar box design.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear /equipment inspections, line patrols, line inspections and other observations all place priority in the integrity and testing of earthing systems. Data on earthing systems are stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
STAKEHOLDER RISKS	
Damage caused by third parties who do not wish to pay	Methods: Resources are assigned to making sure that third party damage repair costs are recorded. Details: Incidents are followed-up and accounts are sent. Bad debts are chased until the issues are resolved. Conclusion: Stakeholders understand that debts will be followed up.
RISK ASSOCIATED WITH DIFFERENT LIFE CYCLE PHASES OF ASSETS	
Early life and end of life failures	Methods: Recognises that early and end of life failures occur and have contingencies in place to control these. Details: Contingencies include back feeds set up or things such as emergency spares. Conclusion: The reality is that the probability of early, and end, of life failure rates are higher with most components.

TABLE 7.4: IDENTIFIED RISKS AND MITIGATION OF RISKS TO DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS

Distribution substations, switchgear and underground systems are generally not insured.

7.3.4 Other Equipment

Table 7.5 summarises other secondary distribution assets risk assessment and mitigation.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
PHYSICAL FAILURE RISKS	
Electronic Software	Methods: Current copies taken and kept off site. Details: Backup copies of SCADA and other software are kept on and off site. Conclusion: A software problem with key equipment is a low probability high impact risk.
Repeater failure	Methods: Maintain the existing systems to a reliable standard. Establish a level of redundancy on key links during the planning period. Details: Continue with renewal strategy to keep links maintained and renewed so that they have current supported equipment. Long term development plans are included to reduce dependency on one or two key links. Conclusion: TLC's automation is very important for the network operation. Repeater links are the backbone of the system.
SCADA Failure	Methods: Renewal plans are in place to keep equipment up to date so that it is reliable and modern equivalent replacement components can be used when failures occur. Details: An independent SCADA expert with knowledge of TLC's and other systems throughout the country advises and helps TLC engineers keep the system up to date, current and reliable. The renewal programme includes an on-going updating strategy to keep the technology current. Conclusion: A failure of the SCADA system especially during periods of network stress will lead to a low probability high impact risk.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Load control plant failure	Methods: TLC has a forward strategy to keep its load control plants renewed and of an age that is supported by suppliers. Legacy high frequency plants now have a low frequency alternative; however it will be a number of years before all relays downstream of legacy plants are reprogrammed or replaced and as a consequence this risk will exist for a number of years. A level of backup between the new plants will be possible through the 33 kV network in addition to the strategy to keep plants up to date and supported. Details: All the 317 Hz static plants are being kept up to date and under maintenance warranties from the suppliers. The legacy 725 Hz plants are being replaced with 317 Hz relay installations. It will take at least five years for relays in customers' meter boxes to be renewed, exchanged or replaced with combination relays and meters. In the meantime the old plants have to be kept running. A spare plant is planned to be set up in a container to cover off a failure of one of legacy plants. A risk to load control going forward is the effects of distributed generation on signal levels. Units are being well sized to cover this risk. Conclusion: TLC's risk of a load control plant failure will reduce due to the renewal programmes included in the Plan. The loss of load control plants will increasingly become a low probability high impact risk, as opposed to the present low to medium probability (old 725 Hz plants), high risk impact.
Flat batteries or failed battery chargers resulting in incorrect operation	Methods: Maintenance and renewal programmes. Critical supplies have generation backup. Details: Batteries and chargers are subject to testing as part of the maintenance programmes and time based renewal. Critical supplies have generator backup. Conclusion: Batteries are critical for the operation of many items of modern equipment.
OPERATIONAL RISKS	
Failure of technical equipment through incorrect or inappropriate use	Methods: Design of equipment, training and on-going monitoring of the activities it is used for. Details: Equipment is designed to be simple to use and specified/rated for its intended use. Training and on-going monitoring of staff and what equipment continually takes place. Conclusion: Care is taken to ensure equipment is used for intended purpose.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear /equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. The SMS also reports on these activities. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority in the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.
NATURAL ENVIRONMENTAL EVENTS	
Seismic	Methods: The need for seismic constraining of all secondary distribution assets is recognised. This equipment is checked and where necessary renewals and or adding seismic constraints are included in forward programmes. Details: Load control equipment set up with protection. Equipment in radio repeater sites secured. Control room and associated support rooms have equipment secured. Conclusion: The need for seismic constraints is a certain but infrequent requirement and it is often overlooked.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Flooding	Methods: Contingencies are in place for events such as loss of access to the control room. Details: The control room is located close to a river that may flood and stop access (last event 1958). Two full copies of all key control room drawings are kept at alternative sites. Contingencies in place to get SCADA, telephone and radio systems going at these alternative sites. Conclusion: Loss of access to the control room is a low probability high impact event.
Earthquake damage to Control Centre	Methods: Contingencies are in place for loss of access to the control centre. A structural check of the strength of the control centre is currently being undertaken. Details: Initial results indicate there is an earthquake risk with the control room. Once the results of this work are available, options for strengthening or relocation will be developed. Conclusion: There is a risk associated with the present building that is currently being quantified.
Wind, snow, ice and other storm hazards	Methods: Renewal and development programmes consider these effects. Details: Radio repeater sites are constructed to withstand wind, snow, and ice. Load control plants are designed to be capable of withstanding storm conditions. Conclusion: Storms affecting secondary assets do occur from time to time. The effects of a key radio repeater site not operating during a storm can be high impact.
FAILURES OUTSIDE OF THE ORGANISATION'S CONTROL	
Harmonics	Methods: TLC is monitoring network harmonic levels. Harmonics have the potential to cause complex customer equipment interference. Details: Harmonics data are being gathered by spot checks and from distribution equipment that is capable of detecting harmonics. These are reconciled with network analysis models. From this on-going research, controls are being put on new customer connections. SWER lines in particular are susceptible to harmonics. Electronic appliances are potentially increasing harmonic levels on these. Harmonics on SWER systems in addition to customer interference have the potential to produce high strength electromagnetic fields. This may be considered in the future to have adverse health effects. Harmonic levels have to be researched and if necessary filtering put in place to remove these effects. At this time no such filtering has been included in this Plan. Conclusion: Harmonics are a credible low probability high impact risk. TLC recognises they need to be monitored and researched.
Voltage Flicker	Methods: TLC uses standard AS/NZS 61000.3.7-2001 with recommended limits. Details: The network analysis program is used to calculate voltage flicker levels. The standard is used to apply these to customer requests. Conclusion: There is a low probability high impact risk if a particular connection generates excessive voltage flicker. Excessive voltage flicker will cause complaints from customers and affect industrial operations. TLC is mitigating this risk by analysing connections that may lead to problems.
Voltage Surges	Methods: Experience has shown that voltage surges in the network cause customers' appliances to be destroyed. Details: TLC deploys arrestors at key points in the network of a rating that restrict surge values. Specifically network standards require arrestors at impedance change points such as transformers (all) and cables. In addition to this TLC has purchased and is giving away to customers 15,000 plug-in protectors via various educational promotions. It also promotes the importance of surge protection being included in the installation of switchboards via news letters, customer clinics, focus groups and newspaper articles. Conclusion: Surge suppression from a customer perspective is a low probability high consequence event.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
STAKEHOLDER RISK	
Extensive amounts of equipment being destroyed by an abnormal event	Methods: In addition to the risk control strategies described in earlier sections, the majority of this type of equipment has backstop insurance. Details: Equipment has back stop insurance in place. Conclusion: Large scale loss of equipment is an on-going risk for TLC.
Risk associated with different life cycle phases of assets	Methods: Recognise that risk of failure is a greater risk at the beginning and end of lifecycle. Details: Have contingencies in place to be able to continue to maintain energy supply to customers if an individual piece of new or old equipment fails. Conclusion: Contingencies are put in place to minimise risk.

TABLE 7.5: RISKS AND MITIGATION OF RISKS ASSOCIATED WITH OTHER SECONDARY DISTRIBUTION EQUIPMENT

Secondary equipment is generally insured under TLC's equipment policies. TLC does not have cover for damage to customers' equipment unless assets are substantial and the public liability policy is triggered.

7.3.5 Risk Focus of Plan

The TLC legacy network was constructed in times when customers had different quality and reliability expectations. Hazard control was to different standards from those that exist today. A high level of risk was acceptable. Today's reliability and loading requirements are pushing much of this old equipment harder than it has ever been pushed over its life.

Documenting and having strategies in place to manage risks is a key aspect of this Plan. A focus of the Plan is to manage and reduce risk. The cost of not completing renewal and other activities to satisfactorily manage risk has a high potential liability cost.

7.4 Risk evaluation

7.4.1 Potential Liability Analysis

Table 7.6 summarises an analysis of the potential liability estimate associated with low/medium probability, high impact events. This table gives an indication of our current best estimates of the potential costs of not controlling these risks.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
CORPORATE		
Corporate systems not in place	Fraud	Experience has shown that fraud could typically cost $200,000 or more per annum. An insurance backstop is in place.
	Strategic plans and direction	Lack of strategic plans and direction will cost the organisation in all aspects of its operation. The cost of lack of direction, motivation and disorganisation/ inefficiency would quickly amount to costs of $1m p.a.
	Environmental	Environmental costs from clean-ups and fines after events such as oil spills. Fines, legal costs and clean-up costs could typically be $100,000 per event.
	Human Resources	High employee turnover quickly adds to costs. A turnover of 20 people p.a. has been estimated to add about $200,000 p.a. to direct and indirect operating costs.
Public Relations	Customer Interfaces	A poor customer relationship leads to many difficulties within the organisation. These include: • Landowner issues. • Repeated complaints to Regulators. • Low staff morale. • Poor and often incorrect public perceptions. The cost of poor public relations is significant and difficult to estimate due to the flow down instabilities that will occur through the organisation and with its customers. Direct expenditure on improving public relations can typically add $200,000 to operating costs. Indirect costs are likely to be greater than these amounts.
Distributed Generation	Investor generators permitted to connect equipment that causes the network to become unstable.	Unstable distributed generation can quickly cause significant damage to TLC, customers and generator equipment. The cost of any such event is related to the size of the plant. TLC has had experience with one event that led to a claim of about $2m.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
ZONE SUBSTATIONS AND VOLTAGE REGULATORS		
Aged equipment that is expensive to maintain, unreliable, the intellectual knowledge to maintain it is no longer available in the industry, it is getting pushed operationally harder than any other time in its life and does not meet today's hazard control expectations in a simple way. (e.g. oil filled switchgear operating in a high fault current, high arc flash energy environment).	Equipment failure, leading to explosion, fire, environmental damage, injury to staff or the public.	Extended outages that cause SAIDI and SAIFI thresholds to be breached. The costs, in addition to repairs, will include fine liabilities for breaching thresholds and potential customer claims. Possible costs if an event of this scale were to occur could be up to $1,000,000. Repairs – The cost of repairs, that could take some time, could quickly escalate from $500,000 to $1,000,000 per event. Environmental damage – Fire on resulting burning oil spills and explosions could quickly escalate from $500,000 to $1,000,000 in costs. Hazard Control – Injury to staff or the public again could quickly escalate to fines and legal costs in the $500,000 to $1,000,000 range.
Electronic equipment and software problems	Equipment not operating or operating incorrectly. (Including protection).	As with aged equipment above.
Security	Insecure sites allowing people to enter them.	Prosecution under the Electricity (Safety) Regulations and HSE Act– potential fines and legal costs of at least $500,000.
Capacity	Capacity of equipment is exceeded and damage results.	As with aged equipment above.
Environmental	Oil spills and transformer falling over during earthquakes.	Repairing of damage after transformers fail. The cost per transformer in zone substations would typically be $200,000 to $500,000 to complete repairs.
Demand growth constraint	Demand growth constraint assumptions are critical in this plan.	If demand growth is faster than the assumptions made and demand billing is not successful in restraining the growth, then the additional cost to the organisation will likely be about $1,000,000 annually.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
OVERHEAD LINES		
Rundown lines in poor condition	Vegetation not controlled to present levels	Reliability indices are exceeding Commerce Commission thresholds; fines to the company are possible. More resourcing required that is focused on repairing faults. Could realistically be expected to add $500,000 to $1m p.a. to operating costs. The costs of putting out rural fires can be substantial. A cost of $50,000 to $100,000 would be typical.
	Lines that are not inspected, patrolled and renewed that are left to rundown with legacy hazard control issues such as under-height conductor	Increase fault costs in the range of $500,000 to $2m p.a. Risk of prosecution and fines by DoL and Energy Safety. The typical OSH fine would be in the order of $100,000 plus legal costs. Electrical safety related fines and legal costs could quickly sum to $500,000 p.a. if lines were left to run down.
	Lines that are in poor condition and cause fault current flows. The fault currents then cause damage to transformers, line connections and from time to time circuit breakers.	Additional fault current damage would increase costs in the order of $200,000 p.a.
	Private Lines affecting TLC's Network	Private lines can cause faults that affect the TLC network. Costs arise with identifying and isolating these faults, particularly if TLC's renewal programme is not being completed and isolating links are not installed at the point of connection. Labour and inconvenience associated with private line issues could quickly add $100,000 p.a. to TLC's operating costs.
Environmental events	Wind, slips, flooding, seismic, lahar, geothermal, volcanic, snow, ice and other storm hazards	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success of the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a.
Quality of components coming into the network as part of the renewal programmes	Components failing before lifecycle expectations, quickly adds to costs	It is estimated that low quality materials that result in assets failing before lifecycle expectations would add $100,000 to $500,000 to operating costs p.a.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Harmonics	SWER systems	TLC is monitoring the harmonic levels on SWER systems and is concerned about increasing harmonic levels due to the increasing use of power electronics. Filtering can be used to remove harmonics at an estimated cost of $50,000 per SWER system. (TLC has over 60 SWER systems).
	Remainder of network	As with SWER systems, TLC is monitoring harmonic levels and connection standards require compliance with the Codes. The tools for overcoming harmonic issues can involve numerous filters and changed transformer vector groups and the like. The cost of overcoming a major harmonic problem such as those found in the irrigation areas of the South Island can quickly escalate to $1m to $2m. The potential damage to customers' equipment and loss of production at major industrial sites would result in similar costs to TLC, insurance companies and customers.
Voltage Surges	Destruction of appliances and poor customer relations	Voltage surges are typically causing $50,000 worth of damage to customers' equipment annually. In an extreme event this figure could reach $1m to $2m worth of damage.
DISTRIBUTION SUBSTATIONS, ASSOCIATED SWITCHGEAR AND UNDERGROUND SYSTEMS		
Earthing systems not being tested, maintained and renewed.	Earth potential rises around failed earthing systems.	Hazard control – earth potential rises that result in human or animal shock and electrocution. Liabilities associated with fines and legal costs in the $100,000 to $500,000 range per event. If systems are not in place to ensure this work is taking place, there is the potential for numerous events.
Loss of Circuit Breaker Electronic Setting Data	Equipment not operating correctly or failing to operate.	Hazard control – Electronic setting data of protection equipment must be correct if equipment is going to operate correctly. Protection equipment not operating correctly results in increased human and animal shock and electrocution risk. Not ensuring equipment is fit for purpose and operating correctly could be expected to attract fines and legal costs of typically $100,000 to $500,000 per event. Equipment Damage – Protection equipment not operating correctly will result in increased equipment damage. Increased damage of about $10,000 to $500,000 per event could quickly result. (The higher amount would come about with an event such as a zone substation transformer failure due to the passage of fault current).
Security	Insecure sites allowing people to enter them.	Prosecution under the Electricity (Safety) Regulations – potential fines and legal costs of $500,000.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Legacy underground systems	Old systems that have been constructed using low cost methods and often using unskilled labour. (The renewal and other operational criteria are monitoring and renewing these cables as required).	Hazard control – many of these old systems (especially in Ohakune, Turangi and part of Taumarunui) consist of PVC insulated, unprotected single core aluminium cables. Excavation contractors often damage these. Neutrals also fail from time to time resulting in customers' installations being exposed to high voltages. The potential cost of not renewing these would be that the occasional event where fines and legal costs of typically $50,000 per event may result.
Other equipment failures such as distribution transformers and related equipment	Lightning and switching surges	Lightning and switching surges can destroy both TLC transformers and also customers' equipment. As discussed in other sections of this plan, TLC installs lightning arrestors throughout the network to minimise the risk of its own, and customers', equipment damage. Lightning and switching surges destroy about $100,000 worth of TLC and customers' equipment annually. Without proper protection this figure is estimated to be a factor of 10 higher.
Component failures	Quality of components and workmanship	Poor quality components and workmanship can quickly add to costs. The level and number of events is variable. TLC has experienced high numbers of component failures in the past due to quality of materials and workmanship. The cumulative cost of poor workmanship or quality of components could quickly add $500,000 to $1m to operating costs.
Capacity failures	Capacity	Ensuring that selected equipment has the correct capacity is part of sound engineering, i.e. equipment must be adequate. As a counter to this, it should not be overrated and thus not generating the correct level of income. A moderate level of capacity failures could quickly add $500,000 to annual operating costs. TLC is also reliant on customers not adding substantially more load or reducing load and overloading, and under loading, equipment. TLC has a load application process in place to minimise this effect; however, from time to time customers do not correctly advise of changes and the cost of operating increases.
Protection systems operating incorrectly	Members of the public or staff receiving a more severe electric shock due to protection system failures. Forest fires and other events that may not have occurred if protection system operated correctly.	Fines and legal costs of up to $300,000 per event. Various claims from customers and insurance companies for damage. These would vary from a few thousand dollars to potentially millions of dollars. Equipment repairs to distribution and possibly, zone substation transformers, i.e. $10,000 to $200,000 typically
Contractors damaging cables	Diggers hitting cables.	Contractors would normally be charged for these events; however, they normally involve a claim against an insurance company, which results in a negotiation. Often it is difficult to get a full payment and admin/engineering time is involved in preparing detailed accounts etc. The cost of these events is typically $5000 per event.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Loss of skill associated with protection	Incorrect setup	Fines and legal costs of up to $300,000 per event. Various claims from customers and insurance companies for damage. These would vary from a few thousand dollars to potentially millions of dollars. Equipment repairs to distribution and possibly, zone substation transformers, i.e. $10,000 to $200,000 typically.
Environmental events	Wind, slips, flooding, seismic, lahar, geothermal, volcanic, snow, ice and other storm hazards.	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success off the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a. Unlike overhead lines, some technical items have insurance backup. These insured events, however, are subject to excesses, which are typically $20,000.
Early life and end of life failures	Back up contingencies including the ability to connect generators.	Backup contingencies include many things such as alternative suppliers. The contingencies vary greatly and it is difficult to put a cost on them. The "back to the wall" solutions are to use generators as an alternative supply. TLC typically spends $200,000 p.a. on its own and hire generators. (Most of these costs go against the individual projects).
Traffic accidents, third party and other damage	Traffic accidents	The vehicle driver picks up much of the costs associated with traffic accidents via insurance companies. Insurance companies are often reluctant to pay out and costs are incurred in arguing with insurance companies/court claims and other administration. Traffic accidents could add about $50,000 p.a. to operating costs associated with insurance companies not paying out full amounts, legal claims and uninsured vehicle owners who cannot afford to pay.
OTHER EQUIPMENT		
Electronic software and hardware	SCADA and radio equipment software and electronic equipment failing and not being backup up.	TLC operations are now reliant on electronic SCADA and radio software and hardware. This software and hardware is backed up and has been kept up to date so that, in addition to the backup, it is fully supported by local agents, manufacturers and suppliers. In the low probability, high consequence event that a major problem ensured, the costs of an extensive repair and replacement of this equipment could quickly approach $1m to $2m. Through the repair period, network operating costs would increase due to the need to manually operate equipment and reliability would reduce due to the time involved in getting staff to site. (Individual repeater failure would have similar consequences but would be more localised).

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Load plant failure	Failure of audio frequency generator or tuning equipment	TLC has a strategy of keeping this equipment modern (317 Hz system) and it is fully supported by the suppliers. An operational load control system is an important part of TLC's demand billing strategy. The importance of load control plants has increased since the deployment of this charging scheme. Failure of a plant could lead to Transpower Regional Co-Incidental Peak Demand (RCPD) charges not being avoided, parts of the network being overloaded, streetlight signals not being sent and timed mostly retail based energy charge period tariff signals not being sent. In the worst case, a house fire could result from a missed night store signal for timed signals. The likely costs of this would be: Missed RCPD reduction opportunities - $500,000 to $1,000,000 Network damage due to overloading typically - $200,000 to $500,000 Streetlights – poor public relations and service to road controlling authorities. The cost is difficult to quantify, but would perhaps be - $10,000 Missed time signals assuming a house fire and fines and legal costs associated with this occurring - $500,000
Backup power supply failures	Flat batteries or failed battery chargers resulting in incorrect operations.	TLC has battery and battery charging renewal programmes in place. Battery failure can lead to many problems, the worst of which would be hazards and equipment damage resulting from a protection system failure. The fines, legal costs and damage repairs resulting from an event of this nature could quickly exceed $500,000 to $1m.
Failure of technical equipment through incorrect or inappropriate use	Equipment destroyed and requiring replacement after an event	TLC puts a lot of effort into making sure equipment is designed to be simple to use and is specified/rated for its intended use. TLC has experienced events when equipment has been destroyed and these typically cost $50,000 to $100,000 per event.
Natural environmental events	Seismic, flooding, wind, ice and other storm hazards.	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success off the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a.

TABLE 7.6: CURRENT BEST ESTIMATES OF THE POTENTIAL COSTS OF NOT CONTROLLING RISKS

7.4.2 Areas where Analysis highlights the need for Specific Development Projects or Maintenance Projects

The analysis in Table 7.6 highlighted the need for the various maintenance, renewal and development programmes outlined in Sections 5 and 6 of this Plan. Most of the risks were offset by the various projects and activities.

Table 7.6 did highlight two areas where TLC is exposed and as such the Plan has been modified to cover these off. Specifically, these are the levels of contingency for risks associated for different lifecycle phases of assets, and the effects of a load control plant failure, given TLC's demand based billing strategy and the importance of load control looking forward into the future.

7.4.2.1 Contingency for Risk Associated with Different Lifecycle Phases of Assets

The normal "bath tub" curve of reliability of components illustrates that most failures occur early and late in most equipment lifecycles. TLC has a number of relatively new assets (as a consequence of the renewal programme), and old assets. There are a relatively high number of assets in the high likelihood of fail regions of the 'bath tub' curve.

The strategy to overcome this risk is to have some form of backup. A key part of this backup strategy is to have generators available for backup. TLC currently has one 165 kVA genset on a truck complete with a 400 to 11 kV transformer and related control/protection equipment. TLC hires in additional generators as needed. Unfortunately, there are no local hire companies and this plant has to come by truck from Auckland, Hamilton, Waihi or New Plymouth. The establishment time is normally about 12 hours from the fault to supply from the generator. A delay of this length is unacceptable to most customers.

The above analysis has highlighted an associated risk. Further analysis has shown that often back-up supplies can be maintained by connecting a reactive power source to the network, as opposed to expensive generators. As a consequence, TLC has instigated the development of mobile reactive power sources to help mitigate this risk, and included it as part of the 2011/12 programme.

7.4.2.2 Effects of a Load Control Plant Failure

TLC's demand billing strategy significantly increases the importance of having reliable load control signals. There is currently no redundancy in injection plants and there is a very limited ability to remove existing plant from service to be used in an emergency at another site.

The analysis in table 7.6 highlighted TLC's exposure to a plant failure and the need for some form of contingency. The development section of the plan includes an allowance for having a contingency plan in place.

7.5 Risks associated with economic downturn and the need for on-going hazard elimination/minimisation

As outlined in other sections, the TLC network assets are old and many were constructed using second hand materials. Many of these assets have hazard risks. This Plan is designed to address these in a prioritised way and by 2020 a significant improvement will be achieved. The revenue required to implement the Plan will require price rises and during times of economic downturn there will be pressure not to move prices. Failing to renew assets will result in unaddressed hazard issues and stakeholders need to be aware of this. (Table 7.6 estimates the potential liability risks).

For example, if TLC's largest asset class, overhead lines, are considered, this Plan includes allowances to replace about 10% of poles, as the 15 year line renewal programme cycles through the network. Strength calculations show typically 30% of poles need renewing to comply with codes. If renewal expenditure is constrained below levels in this Plan, then poor condition and under strength pole hazards will not be addressed.

It is hoped a forward strategic objective of driving the organisation to complete capital works at a lower cost will go a significant way in reducing the lower strength poles that are not renewed as part of TLC's programme.

Risk is being mitigated by the proportion of this comprehensive asset management plan and strategies to make stakeholders aware of the issues. Looking forward, the Plan is to further develop detailed asset data and system, to provide continually improved planning and asset knowledge.

There is a risk however that the political and governance pressure not to do this work nor to increase prices to fund it will stall the hazard renewal programme. It is expected that other pressures such as the Electricity (Safety) Regulations and on-going strengthening of HSE regulations/enforcement will go some way in mitigating this risk.

7.6 Details of Emergency Response and Contingency Plans

7.6.1 Civil Defence

TLC has in place an approved Civil Defence plan and has been involved with the Horizon and Waikato lifelines groups. Staff attends group meetings and contact lists are maintained. Communication channels are set up whenever an event occurs.

Contingency event procedures are invoked whenever supply is lost to 50 or more customers. As events become more serious, more and more layers of contingency action are applied. A staff member has been assigned the responsibility of maintaining, reviewing and updating the Civil Defence Plan.

7.6.2 Event Management

The event management process is initiated when it is likely that 1000 customers will be affected for 10 minutes or 50 customers for 4 hours. As the event worsens, the additional staff layers include Duty Engineer, Engineering Manager, Communication Managers, Staff Welfare Management and Civil Defence functions.

This response and layers of contingency depending on the event seriousness is used to manage events when they occur. TLC has in place a 24/7 service using local people. When an event occurs this is scaled up and additional resources are called in.

The event management procedure is a formal approved procedure and is reviewed/updated annually. Additional rooms around the control room are transformed into communication and co-ordination centres when an event occurs. These rooms have radio plugs, additional telephones, maps, computer connections, emergency lighting and the like, wired in ready for these events. Various staff have nominated responsibilities for staff communications, staff welfare, dispatch, stores etc. when an event occurs.

7.6.3 Seismic

It is anticipated that a seismic event will cause damage to poles and transformers. Depending on the size of the event, the procedure described in the above section will be implemented.

The contingency process would involve despatch of line repair and technical staff. If the control room were destroyed this function would have to be set up at any of the alternative three sites where system drawings are kept and access to internal and external communication systems are available.

Recent analysis of the control centre has indicated that strengthening is required. Options for this will be developed through the coming year.

7.6.4 Lahar

Lahars present a risk on Mount Ruapehu; hence, cables and other equipment are installed away from known Lahar paths where possible. Recent development work on the Whakapapa ski field has seen a number of transformers moved from the known Lahar path. However, some risk of damage has to be accepted in this environment.

TLC has 11 kV lines in the Tangiwai Lahar path, which could affect customers on the Tangiwai feeder if the Lahar level were to be substantially higher than the 2007 event.

A plan was produced in December 2001, dealing with the steps that should be taken and this is reviewed after each Lahar planning meeting. When the 2007 event occurred, no damage resulted because of the planning that had previously taken place.

7.6.5 Emergency Event in Control Room

If an abnormal serious event occurs in the control room or on the network, and the Controller becomes under stress, overworked or unsure of what is needed, he contacts the Duty Engineer who provides additional support.

7.6.6 Emergency Generators

TLC network owns a number of both small and large generators that are used in emergencies. There are several small, compact, electronic inverter units that are made available to customers who have emergency needs. A recent example of their deployment was to two families with essential medical equipment on the end of a remote SWER line. In this case an absentee landowner's trees kept destroying the line and it took a number of weeks before they co-operated and brought in heavy equipment to remove the trees.

Section 8

8. Details of Performance Measurement, Evaluation and Improvements

8.1 Review of Progress against Plan, both Physical and Financial

The comparison between planned and actual expenditure, including the reasons for any variances, are discussed in the following sections.

8.1.1 Capital Performance – both Physical and Financial excluding Line Renewals

Table 8.1 lists the approved 2010/11 planned expenditure and the actual expenditure (excluding line renewals). The numbers in the last column relate to the further detail notes that follow the table.

The financial figures in the section below represent the best possible allocations that could be deducted from the available financial information. Improvements in reconciling between the accounts and asset management systems have been made but more are necessary to make the process more accurate and easy to administer going forward.

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2010/11 Actual**	**2010/11 Planned**	**Note**
Equipment Renewals			
New Transformers	178,068	300,000	1
Protection Relay Contingency	26,329	10,000	2
Radio Systems Contingency	8,282	10,000	3
SCADA Contingency	27,253	15,000	4
Distribution Equipment Contingency	29,546	50,000	5
Specific SCADA Replacements	11,451	36,908	6
Radio Equipment Specific	23,772	29,760	7
Renewals for New Connections Tap-offs etc (including Easements)	23,632	30,000	8
Moving Lines under Electricity Act	30,687	50,000	9
Environmental Projects			
Tawhai Substation	-	40,000	10
Taharoa Substation	88,167	100,000	11
Piripiri Substation	2,356	30,000	12
Hazardous Elimination Renewals			
Hazardous Elimination Renewals - 2 Pole Structures			
Tuhua: Renew 2 Pole Structure (05F10)	23,004	40,000	13
Oruatua: Renew 2 Pole Structure (09U05)	-	50,000	14
National Park: Renew 2 Pole Structure (15L01)	-	50,000	15
Aria: Renew 2 Pole Structure (T1958)	29,989	15,000	16
Waitomo: Renew 2 Pole Structure (T466)	27,693	40,000	17
Te Kuiti South: Renew 2 Pole Structure (T656)	29,551	55,000	18
Waitomo: Renew 2 Pole Structure (T70)	34,675	40,000	19
Rangipo/Hautu: Renew 2 Pole Structure (11S15 Recloser 5168)	98,298	95,000	20

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2010/11 Actual**	**2010/11 Planned**	**Note**
Ohakune: Burns Street 2009/10 Carry over	28,230	-	21
Oruatua: Safety Renewal (09T05) Carry over	69,699	-	22
Hazardous Elimination Renewals - Ground Mounted Transformers			
Matapuna: Ground Mounted Transformer (01B13)	15,855	15,000	23
Ohakune: Ground Mounted Transformer (20L03)	32,938	40,000	24
Hazardous Elimination Renewals - Switchgear Renewals			
Borough: Substation Hazardous Switchgear	58,807	100,000	25
Waitete: Substation Hazardous Switchgear	57,991	90,000	26
Taharoa: Renew Aged Substation Hardware	1,141	50,000	27
Additional Hazardous Switchgear Renewal			
Western: Switchgear Feeder Renewal (08I55)	23,975	-	28
Ohakune: Switchgear Renewals (20L51)	37,878	40,000	29
Kuratau: Switchgear Renewals (08R18)	27,174	40,000	30
Chateau: Switchgear Renewals (15N01)	22,108	40,000	31
Pillar Box Replacements	59,277	90,000	32
Cummulative Capacity (System Growth)			
Ohakune :Turoa Feeder Voltage Upgrade	78,010	85,000	33
Reliability Projects			
Tawhai: Substation Automation (ABS 5663)	5,470	40,000	34
Whakamaru/Mokai: Feeder Tie (Switch 489)	9,606	20,000	35
Whakamaru/Mokai: Feeder Tie (Switch 480)	9,515	20,000	36
Oparure: Feeder (Switch 243)	9,789	25,000	37
Oparure: Off Take Site (Switch 757)	22,620	40,000	38
Oparure/Piopio: Feeder Tie (Switch 269)	26,703	40,000	39
Rangipo/Hautu: Additional Switches	40,167	40,000	40
Southern/Raurimu: Automation (Swtich 5235)	9,690	25,000	41
Te Kuiti South: Tie (Switch 444)	27,126	25,000	42
Turoa: Feeder Automation (Switch 6600)	-	20,000	43
Whakamaru/Tihoi: Inter Tie (Switch 428)	9,606	20,000	44
Specific Equipment Renewals			
Borough: Substation RMU	89,082	70,000	45
Kuratau: Circuit Breaker Replacement	61,525	80,000	46
Whakamaru: Load Control Plant Renewal	208,669	-	47
Hangatiki: Load Control Plant Renewal	199,112	-	48
2010/11 Meter Replacement Project	6,047	120,000	49
Piripiri: 33kV Breaker Replacement	-	45,000	50
Piripiri Substation Fault	1,969	-	51
Arohena: Install 33kV Breaker Carry over	19,278	-	52
Nihoniho: 2009/10 Transformer Renewal Carry over	35,202	-	53

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2010/11 Actual**	**2010/11 Planned**	**Note**
Customer Driven			
New Connections	416,893	300,000	54
New Subdivisions	18,019	105,000	55
Tangiwai Sawmill Switchgear (Industrial Connections)	57,221	-	56
Miraka Milk Plant Work (Industrial Connections)	796,008	20,000	57
Industrials New Connections (General)	19,309	130,000	58
33kV Line Development	-	200,000	59
Substation Upgrade (Te Anga)	569,368	225,000	60
Total	**3,873,834**	**3,286,668**	

TABLE 8.1: ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS

Further notes to Table 8.1 Actual and Planned Capital Expenditure excluding Line Renewals.

Equipment Renewals:

1. New Transformers
   Within estimate. The economic downturn resulted in less demand for transformers.
2. Protection Relay Contingency
   Exceeds estimate. There were more relay failures than anticipated. The expenditure also included CT replacements made in conjunction with relay replacement.
3. Radio Systems Contingency
   Within estimate. No significant unexpected events occurred with the radio system.
4. SCADA Contingency
   Exceeds estimate. A number of replacement remote terminal units were required due to failures caused by lightning and fibre drivers.
5. Distribution Equipment Contingency
   Within estimate. Underspend due to less distribution equipment failing in service than in a typical year.
6. Specific SCADA Replacements
   Less SCADA work than anticipated was needed to be done. Some of the contingency work was incorrectly coded.
7. Radio Equipment Specific
   Within estimate. Less work was undertaken in anticipation of the need to upgrade some of the analogue links to a narrower band width due to changes to spectrum licensing requirements.
8. Renewals for New Connections tap-offs and Easements
   The costs were below estimate due to reduced economic activity.
9. Moving lines under Electricity Act
   Within budget. There were fewer requests for line movement due to road works than anticipated.

Environmental Projects:

10. Tawhai Substation
    Physical work was initiated but no costs came through the accounting system. The project was delayed to later in the year due to the need to work around the ski season and the availability of technically skilled resources. Work was completed in the 2011/12 year.

11. Taharoa Substation
    The project was completed for less than estimate.

12. Piripiri Substation
    The project did not eventuate due to the Speedys Road distributed generation connection proceeding. A new substation was constructed closer to the generation connection and the need to upgrade this site was largely alleviated. The site is still used as a switching point and some minor capital works associated with this upgrading were completed.

Hazardous Elimination Renewals:

13. Tuhua: Renew 2 pole structure (05F10)
    Project completed within budget. Conditions on site were more straightforward than anticipated.

14. Oruatua: Renew 2 pole structure (09U05)
    The project was substantially completed; however, the costs have not been correctly allocated to the project. It is possible that some will be rolled forward into the 2011/12 year.

15. National Park: Renew 2 pole structure (15L01)
    Project rolled over to 2011/12 due to unavailability of technical resources.

16. Aria: Renew 2 pole structure (T1958)
    Project completed. Exceeded budget due to generator hire and the need for work to be performed using live line techniques that were not included in the estimate.

17. Waitomo: Renew 2 pole structure (T466)
    Project completed within budget. Conditions on site were more straightforward than anticipated.

18. Te Kuiti South: Renew 2 pole structure (T656)
    Project completed within budget. Back feeds allowed smaller shutdown areas, thus reducing costs.

19. Waitomo: Renew 2 pole structure (T70)
    Project completed within budget. Conditions on site were more straightforward than anticipated.

20. Rangipo/Hautu: Renew 2 pole structure (11S15 Recloser 5168)
    Project completed slightly above budget due to the complexity of the task.

21. Ohakune: Burns Street 2009/10 Carry over
    This project was completed in the 2009/10 financial year, where it was budgeted at $60,000 and expenditure totalled $20,588. 2010/11 costs are for work performed late in the previous year.

22. Oruatua: Safety renewal (09T05) Carry over
    This project was budgeted in the 2009/10 financial year at $50,000. 2009/10 expenditure totalled $19,512. Installation costs have carried over into the 2010/11 financial year. The transformer 11kV switch was faulty and had to be returned to the manufacturer for repair. This caused delays and added to costs.

23. Matapuna: Ground Mounted Transformer (01B13)
    Project completed close to budget. Replaced existing unit with an enclosed transformer.

24. Ohakune: Ground Mounted Transformer (20L03)
    Project completed within budgets. Works proved straightforward and went more smoothly than estimates allowed for.

25. Borough: Substation Hazardous Switchgear
The project was delayed due to faults detected in new switchgear and relays as part of testing. Equipment had to be returned to Asian manufacturers and this delayed the project. The remainder of work was rolled forward into 2011/12.

26. Waitete: Substation Hazardous Switchgear
Project initiated and materials sourced. Lack of skilled resources meant that the completion of works rolled forward into the 2011/12 year.

27. Taharoa: Renew aged Substation Hardware
Initial engineering work was completed; however, the project was delayed due to the need for customer agreement to fund these improvements through on-going charges. Negotiations with the customer are continuing.

28. Western: Switchgear Feeder Renewal (08I55)
This project was budgeted for the 2009/10 financial year at $40,000. The task was more complex and technical than anticipated and a section of cable needed to be replaced. The associated delays resulted in costs rolling forward into the 2010/11 year.

29. Ohakune: Switchgear Renewals (20L51)
Project completed within budget. A new transformer was installed along with a new switch.

30. Kuratau: Switchgear Renewals (08R18)
Equipment was purchased; however, some costs were rolled forward into the 2011/12 year due to lack of technical resources to complete the project.

31. Chateau: Switchgear Renewals (15N01)
Equipment was purchased; however, some costs were rolled forward into the 2011/12 year due to lack of technical resources to complete the project.

32. Pillar Box Replacements
Less pillar boxes were necessary than forecast – 44 rather than 50. The average cost per pillar box was also less than anticipated.

Cumulative Capacity (System Growth):

33. Ohakune: Turoa Feeder Voltage Upgrade
Project substantially completed by year end. Works had to be completed around the ski season and delays occurred due to difficulties sourcing technical resources during the summer construction period.

Reliability Projects:

34. Tawhai: Substation Automation (ABS 5663)
Project initiated; however, it was held up due to the need for technical resources over the summer construction season. The costs incurred were for materials and design. The project rolled forward into 2011/12.

35. Whakamaru/Mokai: Feeder Tie (Switch 489)
As for 34 above.

36. Whakamaru/Mokai: Feeder Tie (Switch 480)
As for 34 above.

37. Oparure: Feeder (Switch 243)
As for 34 above.

38. Oparure: Off Take Site (Switch 757)
As for 34 above.

39. Oparure/Piopio: Feeder Tie (Switch 269)
Project completed. Work execution was straightforward and without complications.

40. Rangipo/Hautu: Additional Switches
    Project completed close to budget.

41. Southern/Raurimu: Automation (Switch 5235)
    As for 34 above.

42. Te Kuiti South: Tie (Switch 444)
    Project completed close to budget.

43. Turoa: Feeder Automation (Switch 6600)
    The project was delayed due to difficulty sourcing appropriate materials and rolled forward into 2011/12.

44. Whakamaru/Tihoi Inter Tie (Switch 428)
    As for 34 above.

Specific Equipment Renewals:

45. Borough: Substation RMU
    On-going project. Work completed to date has exceeded the original budget due to site complexity, sourcing skilled resources and delays in work execution. Costs will carry over into the 2011/12 financial year.

46. Kuratau: Circuit Breaker Replacement
    Project completed. This project proved very similar to previous circuit breaker projects. All went smoothly and the job was completed well within budget.

47. Whakamaru: Load Control Plant Renewal
    This project was carry over work budgeted in the 2009/10 financial year. The project had been delayed due to a lack of suitable technical resources. The project has now been completed.

48. Hangatiki: Load Control Plant Renewal
    This project was carry over work budgeted in the 2009/10 financial year. The project has now been completed.

49. 2010/11 Meter Replacement Project
    On-going project. Costs to date incurred on investigation and planning. Work will be delayed until a final decision has been made on the advanced meter rollout project.

50. Piripiri: 33kV Breaker Replacement
    The project did not proceed for the reason described in 12 above.

51. Piripiri Substation Fault
    Refer to 12 above.

52. Arohena: 33kv Breaker Upgrade Carry over
    This project was completed late in the 2009/10 financial year. This was primarily due to final detailed engineering plans resulting in more work being necessary than originally envisaged and cost overruns incurred by a shortage of resources with the technical understanding to perform the work.

53. Nihoniho: 2009/10 Transformer Renewal Carry over
    The Nihoniho transformer was hit by lightning in 2009 and had to be replaced. Labour and installation costs carried over from 2009/10 due to the late arrival of the transformer.

Customer Driven:

54. New Connections
The new connections budget was reduced to take into account the effects of the economic downturn; however, there has been a higher than expected upsurge in new connections that resulted in expenditure being greater than the reduced estimate.

55. New Subdivisions
The estimate was underspent due to a reduced level of subdivision activity associated with the economic recession.

56. Tangiwai Sawmill Switchgear
This expenditure was an industrial increased capacity customer requirement. The investment is being funded through increased line charges.

57. Miraka Milk Plant Work
This project was completed at the customer's request. It is being funded from dedicated asset charges. The bulk of the expenditure for the 2010/11 year was related to materials.

58. Industrials New Connection contributions
Expenditure was less than estimated due to the impact of the economic downturn on general industrial customers.

59. 33kV Line Development
This allowance was for an expected increase in reliability requested by the Iron Sands operation. The customer delayed its intent to carry out a reliability improvement and therefore the allowance was not spent.

60. Te Anga Substation Development
Te Anga was developed as a new zone substation site for the Speedys Road generation connection that is described in 12 above. The investment is being funded through dedicated asset charges to Speedys Road Hydro.

8.1.2 Line Renewal (Capital) Performance – both Physical and Financial

Table 8.2 lists the actual planned line renewal expenditure and the approved 2010/11 expenditure. The numbers in the last column relate to the further detail notes that follow the table.

LINE RENEWAL CAPITAL EXPENDITURE			
Line Renewal Projects	**2010/11 Actual**	**2010/11 Planned**	**Note**
33kV Lines			
Taharoa A 33kV (301-02) - Line Renewal	91,263	104,000	1
Turangi 33kV (605-01) - Line Renewal	-	107,744	3
Kiko Rd 33kV (606-02) - Line Renewal	116,451	78,724	2
11kV Lines			
Aria 11kV (114-02) - Line Renewal	64,953	79,144	1
Benneydale 11kV (103-01,02,03) - Line Renewal	37,162	40,014	1
Gravel Scoop 11kV (109-09) - Line Renewal	-	107,504	3
Hakiaha 11kV (401-02) - Line Renewal	107,647	115,232	1
Rangitoto 11kV (106-06) - Line Renewal	340,638	421,356	1
Raurimu 11kV (410-01) - Line Renewal	160,184	222,924	1
Tangiwai 11kV (416-04) - Line Renewal	-	140,434	3
Turoa 11kV (415-01) - Line Renewal	-	534,924	3
Waitomo 11kV (108-01,02) - Line Renewal	131,379	189,124	1
Rangipo-Hautu 11kV (424-01) - Line Renewal	-	368,160	3
National Park 11kV (411-03) - Line Renewal	273,757	277,805	1
Mahoenui 11kV (113-02) - Line Renewal	61,736	49,670	2
Maihiihi 11kV (111-09) - Line Renewal	238,259	124,320	2
McDonalds 11kV (110-02) - Line Renewal	198,171	189,902	2
Mokai 11kV (123-03) - Line Renewal	340,721	305,042	2
Mokauiti 11kV (115-02) - Line Renewal	130,144	155,958	1
LV Lines			
Rangipo-Hautu LV (424-01) - Line Renewal	84,620	80,000	2
LV Work on Rangipo Hautu Carryover	14,522	-	4
McDonalds LV (110-02) - Line Renewal	-	45,000	5
Emergent			
Line Emergent Unplanned	1,064,724	1,200,000	6
Total	**3,456,331**	**4,936,981**	

TABLE 8.2: PLANNED AND ACTUAL LINE RENEWAL CAPITAL EXPENDITURE

Further notes to Table 8.2 Planned and Actual Line Renewal Capital Expenditure.

1 Detailed line inspection and analysis revealed less work was needed than originally anticipated. This combined with improved operational efficiency resulted in line renewal work being completed below budget. Some of these line renewals may incur costs carried over into the next financial year.

2 Line renewal work exceeded budget. This was primarily due to detailed line inspections and analysis revealing more complex work was required than originally estimated. Other cost-adding factors included difficulty accessing land and reaching customer acceptance of the outages necessary. The latter resulted in some live-line techniques being needed and/or the additional costs of generators being incurred.

3 The expenditure for work on these lines has not been incurred in the 2010/11 financial year. Work was subsequently completed.

4 This portion of Rangipo/Hautu work was originally budgeted at $60,000 in 2009. $20,588 of expenditure was incurred in the 2009/10 financial year. The Rangipo/Hautu project progressed slowly. In order to comply with customer expectations, work was done in small chunks. This, along with difficulty sourcing sufficient manpower, extended the timeframe taken.

5 For better utilisation of resources and the associated cost savings, LV in inspections are now planned to occur, where possible, in conjunction with 11 kV inspections in the same area. This project has been rescheduled to coincide with the McDonalds 11 kV feeder inspection.

6 Emergent line renewals - expenditure necessary to carry out urgent capital repairs to maintain supply and remove hazards - was less than estimated. The biggest contributor to the non completion of a number of the technically related capital renewal programmes was the difficulty of obtaining technical resources. This shortage was amplified by the need to complete a number of large customer driven projects in relatively short time frames. Over the past 10 years, skilled technical resources have been exposed to more international markets and at the same time training has reduced. This has put increased pressures on resource availability. TLC's strategy is to train local people to fill this gap. There is, however, a time delay in this process that has lead to a shortage in the interim. TLC's capital programmes (development and renewal) have been effective in ensuring that reliability targets have been met and that capacity is available to meet customer requirements at a price they are able to afford.

8.1.3 Direct Maintenance Expenditure

The comparison between estimated and actual expenditure and the reasons for this are discussed in the following sections on a category by category basis. Table 8.3 lists the estimates from the 2010/11 plan and the actual amounts spent. The note numbers in Column 4 relate to the further detail notes below the table. The 2010/11 planned figures vary slightly from those estimated in the 2011 AMP due to on-going refinements in reporting systems.

DIRECT MAINTENANCE EXPENDITURE			
Description	**2010/11 Actual**	**2010/11 Planned**	**Note**
Cable Maintenance			
33/11kV Cable Repairs and Terminations	28,923	53,000	1
LV Cable Maintenance	2,930	31,800	2
Ground Pillar Box Repairs	13,928	31,800	3
Cable Location Costs		1,060	4
Sub Total	**45,781**	**117,660**	
Line Maintenance			
33kV Line Maintenance	12,314	63,600	5
11kV Line Maintenance	64,756	169,600	6
Low Voltage Line Maintenance (including Permanent Disconnections)	38,972	31,800	7
Street Light Network Maintenance	27,002	8,480	8
Line Disconnections for Safety	24,377	29,680	9
Sub Total	**167,421**	**303,160**	
Tree Maintenance			
Tree Trimming - Planned (maintenance of existing)	360,554	469,200	10
Tree Trimming - Emergent/Faults (initial work)	260,730	193,800	11
Tree Recoveries	-50,516	-30,600	12
Sub Total	**570,768**	**632,400**	
Line Faults			
33 kV Faults	66,466	26,500	13
11 kV Faults	556,489	455,800	14
LV Line Faults	265,956	318,000	15
Substation Faults	12,850	31,800	16
Standby Faults	171,689	196,100	17
Sub Total	**1,073,450**	**1,028,200**	

DIRECT MAINTENANCE EXPENDITURE			
Description	**2010/11 Actual**	**2010/11 Planned**	**Note**
Zone Substation Maintenance			
Ground Maintenance at Zone Subs and Voltage Regulators	4,593	15,900	18
Building Maintenance at Zone Subs	16,507	21,200	19
Zone Substation Planned Maintenance	101,369	53,000	20
Zone Substation Unplanned Maintenance	18,508	10,600	21
Zone Transformer Planned Maintenance	64,520	84,800	22
Zone Transformer Unplanned Maintenance	18,441	5,300	23
Protection & Control Equipment Maintenance	1,986	15,900	24
Batteries/Chargers Replacement & Maintenance	24,180	21,200	25
Substation Energy Costs	14,623	10,600	26
Substation Rates	546	6,890	27
Substation Rents	5,494	8,480	28
Sub Total	**270,766**	**253,870**	
Distribution Transformer Maintenance			
Ground Mounted Transformer Maintenance	47,950	74,200	29
SWER Earthing Maintenance	5,491	74,200	30
Pole and GM Transformer Maintenance	49,012	58,300	31
Transformer Changes Due to Corrosion etc	20,175	5,300	32
Other Distribution Transformer Site Maintenance	3,490	5,300	33
Sub Total	**126,118**	**217,300**	
Technical Equipment Maintenance			
Northern Load Plant Maintenance	26,382	22,260	34
Southern Load Plant Maintenance	23,321	10,600	35
Repeater Site Maintenance	11,598	21,200	36
Repeater Site Rentals	2,543	5,300	37
Radio Maintenance	12,497	5,300	38
Radio Licences	18,915	26,500	39
SCADA Maintenance	17,590	31,800	40
Line Circuit Breaker Maintenance	7,811	26,500	41
Line Regulator Maintenance	808	5,300	42
Fuse Switches/Till Boxes Maintenance	3,214	3,180	43
Strategic Spares Storage	386	21,200	44
Mobile Generators	5,411	10,600	45
Generator / Transformer & Equipment	550	10,600	46
Sub Total	**131,027**	**200,340**	
Total	**2,385,331**	**2,752,930**	

TABLE 8.3: DIRECT MAINTENANCE EXPENDITURE

Further notes to Table 8.3 Direct Maintenance Expenditure

Cable Maintenance:

1 33/11kV cable maintenance was below estimate due to less cable faults occurring.

2 LV cable maintenance had a smaller number of cable problems than anticipated.

3 Ground pillar box repairs were minimised. The renewal programme and modified pillar box design assisted in achieving this.

4 Cable location costs were not incurred during this period.

Line Maintenance:

5 33kV line maintenance was under estimate due mostly to the reduced number of abnormal events occurring during the year that required follow up maintenance.

6 11kV line maintenance was under estimate due mostly to the reduced number of abnormal events occurring during the year that required follow up maintenance.

7 Low Voltage line maintenance was above estimate due mostly to the costs associated with permanent disconnections.

8 Street light maintenance exceeded estimates mostly due to problems associated with lack of ripple control signals and underground cable repairs on circuits TLC owns.

9 Line disconnections for safety expenditure was close to budget. Safety disconnections primarily include customer requests, property fires and lines down.

Tree Maintenance:

10 Planned tree trimming involves maintaining vegetation that has been previously trimmed. The expenditure on this category was less than anticipated, due in part to resources being involved in emergent tree trimming work.

11 Emergent tree trimming includes vegetation being cut for the first time or as the result of faults. This expenditure was higher than anticipated due to the need to cut trees in some of the more remote areas to clear persistent faults.

12 Tree recovery income was higher than budget with more chargeable works being undertaken than estimated.

Line Faults:

13 33kV line faults exceeded budget. This was mainly due to extreme weather events – especially during September and October.

14 11kV line faults exceeded budget. This was mainly due to extreme weather events – especially during September and October

15 LV line faults faired better than expected. In part this was due to blown fuses being tracked closely in the asset management system, enabling second visits for overloading to be charged to customers.

16 Substation fault expenditure was less than budget, with fewer incidents occurring than anticipated.

17 Standby fault expenditure is close to budget.

Zone Substation Maintenance:

18 Ground maintenance at zone substations and voltage regulators was below budget with less work being required than envisaged.

19 Building maintenance at zone substations was close to expectations. Window replacement at Marotiri constituted about half of the costs.

20 Zone substation planned maintenance exceeded budget mostly due to the increased labour and transport costs associated with completing the work. Technical resources had to be brought in from outside the district and there were also additional costs associated with the need to familiarise new staff.

21 Zone substation unplanned maintenance exceeded estimates due to more unexpected failures than anticipated.

22 Zone transformer planned maintenance cost less than anticipated.

23 Zone transformer unplanned maintenance exceeded budget. This was in part due to cost incurred with the failure of the Piripiri power transformer.

24 Protection and control equipment maintenance expenditure was less than expected. In part, this is due to some costs being allocated incorrectly.

25 Batteries/chargers replacement and maintenance expenditure was a little higher than anticipated due to more batteries needing to be replaced in this financial year.

26 Substation energy costs exceeded budget. Analysis of expenditure indicates the budget was underestimated.

27 Substation rates appear lower than anticipated due to incorrect posting of costs. The budgeted figure is indicative of actual costs.

28 Substation rents were lower than anticipated. This was partially due to land purchases (eg Te Anga, Piripiri) reducing rental costs.

Distribution Transformer Maintenance:

29 Ground mounted transformer maintenance expenditure was less than budget due to insufficient suitable resources to carry out all of the planned works. These planned works will be carried over into the next financial year.

30 SWER earthing maintenance was less than anticipated due to the annual testing identifying less repairs required than in previous years.

31 Pole and ground mounted transformer maintenance was within budget with slightly less transformer repairs than anticipated.

32 Transformer changes due to corrosion is over budget; however, as replacement and maintenance schedules improve, the costs being incurred in this category are significantly reducing.

33 Other distribution transformer site maintenance was within budget.

Technical Equipment Maintenance:

34 Northern load plant maintenance exceeded budget as Gadsby Road and Wairere load control plants required overhauling.

35 Southern load plant maintenance exceeded budget. The container fan at Ongarue failed and needed replacement. The southern load control plant service connection agreements also contributed to a large portion of the costs.

36 Repeater site maintenance was below budget with less work being required than estimated.

37 Repeater site rentals were within budget.

38 Radio maintenance exceeded budget due to costs incurred flying technicians into remote sites for a number of emergency repairs.

39 Radio licences were within budget.

40 SCADA maintenance was below budget with the system remaining stable throughout the year.

41 Line circuit breaker maintenance tracked below budget. Due to technical resource availability, some of this work could not be done and, as a consequence, a level of prioritisation took place. The work that was not completed was rescheduled into the 2011/12 year.

42 Line regulator maintenance is under budget as planned maintenance work has not been completed due to a lack of suitable resources. These works have been rescheduled into the next financial year.

43 Fuse switches and Till box maintenance expenditure was close to budget.

44 Strategic spares storage costs were low with minimal stock being held.

45 Generator truck costs were less than budget.

46 Generator/transformer and equipment is under budget as planned maintenance work has not been completed due to a lack of suitable resources.

Overall, the direct maintenance expenditure was about 8% less than the estimates.

The above notes outline the expenditure variances and the reasons for them and general progress against maintenance initiatives and maintenance.

8.1.3.1 Effectiveness of Direct Maintenance Programmes

The effectiveness of these programmes is summarised in Table 8.3a below. More detail is also included in subsequent sections where a gap analysis and identification of improvement initiatives is completed. (Refer to Section6, table 6-1 for initiatives and programmes).

EFFECTIVENESS OF DIRECT MAINTENANCE PROGRAMMES	
Maintenance Initiative and Programme	**Effectiveness**
Overhead lines and cables (including poles).	Patrols, inspections and follow-ups have contributed to controlling hazards and improving reliability. Emergent work has been necessary to rectify unplanned events and overcome legacy problems. The first 15 year inspection cycle is due for completion in 2020.
Vegetation	24,629 trees have been worked on during the financial year. The fell rate is relatively high (80%) and being maintained. Customers and most plantation owners are becoming increasingly aware of tree issues.
Zone substations	The programme has been effective in maintaining zone substations and ensuring components operate to industry life expectancies. Different maintenance schedules for new equipment versus legacy technology have been allowed for.
Pole mounted transformers	Effective in maintaining transformer stock and ensuring hazard control equipment such as earthing were inspected and tested.
Ground mounted transformers	Effective in maintaining ground mounted stock and ensuring hazard control equipment such as earthing is inspected and tested. Hazard elimination (both worker and public) is being addressed in the programme by introducing double locking and covering exposed terminals in the transformer cubicles.
Service boxes	Effective in ensuring service boxes are secure, labelled and hazards are controlled.
SCADA	Effective in ensuring the SCADA system is robust and operates reliably, particularly when the network is under stress.
Communication	Effective in ensuring the communication system operates reliably, particularly when the network is under stress.
Load control	Effective in ensuring the northern system operates until the remaining ripple relays are changed out. Effective in ensuring the newer electronic equipment is maintained to manufacturer's expectations.
Three phase reclosers and automated switches	Effective in ensuring that these devices operate reliably and to correct protective settings.
Voltage regulators	Effective in ensuring that the equipment operates reliably and voltage is maintained within statutory limits.
SWER systems	Effective in ensuring earthing systems are being maintained. There are a number of new initiatives currently being investigated to improve this further in conjunction with the development of the network analysis programme.
Fault inspections	Effective in identifying hazards and stopping repeat tripping and unexplained faults.
Other inspections	Effective in continually monitoring the network and developing an understanding of issues such as harmonic current flows.
Overall network reliability and security	The maintenance programmes have been effective in ensuring network reliablility is meeting forecasts.
Overall network operating costs	The maintenance programmes have been effective in ensuring TLC's network operating costs are within the industry bands (refer to PWC industry comparisons of operation costs).

TABLE 8.3A: SUMMARY OF THE EFFECTIVENESS OF MAINTENANCE PROGRAMMES

8.1.4 Indirect Maintenance Expenditure on System Management and Operations

Table 8.4 lists the actual spends and the detailed estimates from the 2010/11 plan.

INDIRECT MAINTENANCE EXPENDITURE			
Description	**2010/11 Actual**	**2010/11 Planned**	**Note**
Recoveries	-297,940	-269,770	1
Vehicles and Equipment	100,360	90,630	2
Staff Costs	1,304,220	1,278,062	3
Consultants and Inspections	219,140	287,790	4
Corporate Allocations	174,885	115,981	5
Sundry/Equipment Maintenance	56,824	58,392	6
Other Expenditure	104,670	28,620	7
Total	**1,662,107**	**1,589,705**	8

TABLE 8.4: INDIRECT MAINTENANCE EXPENDITURE ON SYSTEM MANAGEMENT AND OPERATIONS

Further notes to Table 8.4 Indirect Maintenance Expenditure.

1 Total recoveries from capital works to cover the cost of engineering time associated with capital works were slightly higher than estimated.

2 Vehicle costs were slightly greater than estimates due mostly to higher fuel costs.

3 Staffing costs were close to estimate.

4 Helicopter patrols and consultants were less than estimated due to initiatives to minimise the use of these services.

5 Corporate re-allocations were greater than estimates mostly due to legal costs associated with distributed generation and other disputes.

6 Equipment and engineering/asset management costs were slightly less than estimates.

7 Other expenditure tracked a little higher than estimated due to miscellaneous associated costs that were allocated into this area.

8 Overall, Asset Management and Engineering indirect expenditure tracked higher than budget by $72,402, driven by corporate allocations.

The industry comparisons completed independently[1] of disclosed information indicate that TLC has the fourth lowest operating cost per km of line length when compared to other network businesses. It is acknowledged that these figures are an indication only but they do show that TLC's operating costs are effective by industry comparison.

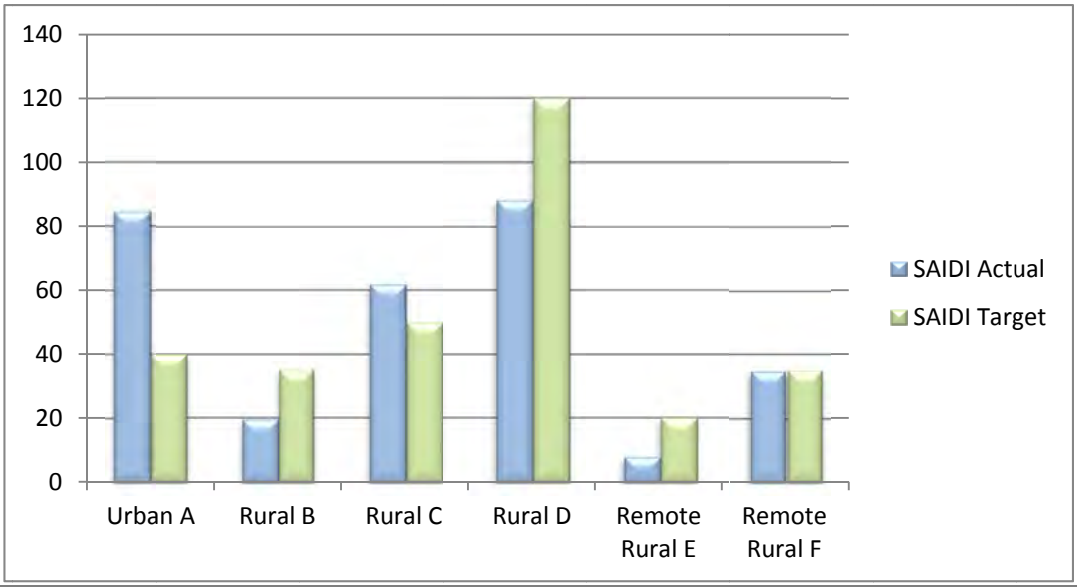
1 PWC (PricewaterhouseCoppers) Electricity Line Business 2011 Information Disclosure Compendium

8.2 Evaluation and comparison of actual performance against targeted performance objectives

8.2.1 Consumer Oriented Performance Targets – Asset Related

8.2.1.1 SAIDI Performance

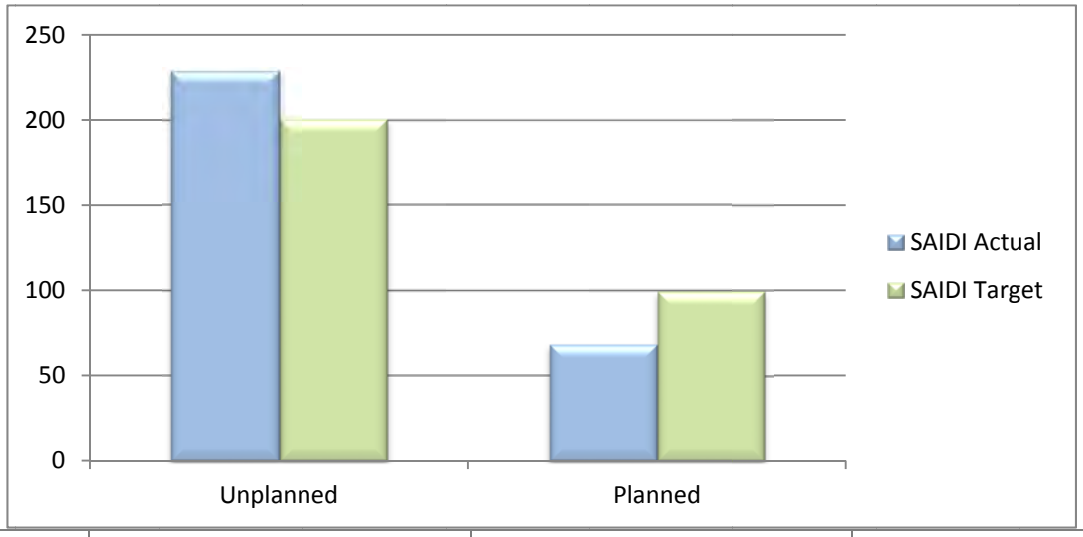
Table 8.5 lists the SAIDI performance by service level areas (refer to section 4 for service level area explanation) for the year 2010/11. Row 3 lists the variance for the 2010/11 year.



SAIDI Target	40	35	50	120	20	35	**TOTAL**	**300**
SAIDI Actual	84.61	19.52	61.79	88.34	7.95	34.69	**TOTAL**	**296.91**
Variance	112% (U)	44% (F)	24% (U)	26% (F)	60% (F)	1% (F)	**TOTAL**	**1.03% (F)**

TABLE 8.5: SAIDI PERFORMANCE 2010/11 AGAINST TARGET BY SERVICE LEVEL

The split between unplanned and planned SAIDI was 228.84 and 68.07 respectively. This compares against a target of 200.6 unplanned and 99.4 planned. Table 8.5A illustrates this.



SAIDI Target	200.6	99.4	**TOTAL**	**300**
SAIDI Actual	228.84	68.07	**TOTAL**	**296.91**
Variance	14.08% (U)	-31.52% (F)	**TOTAL**	**-1.03% (F)**

TABLE 8.5A: SAIDI PERFORMANCE 2010/11 AGAINST TARGET BY PLANNED/UNPLANNED

8.2.1.1.1 Explanation of Significant Variances

There are two significant variances in the 2010/11year. The reasons for these were:

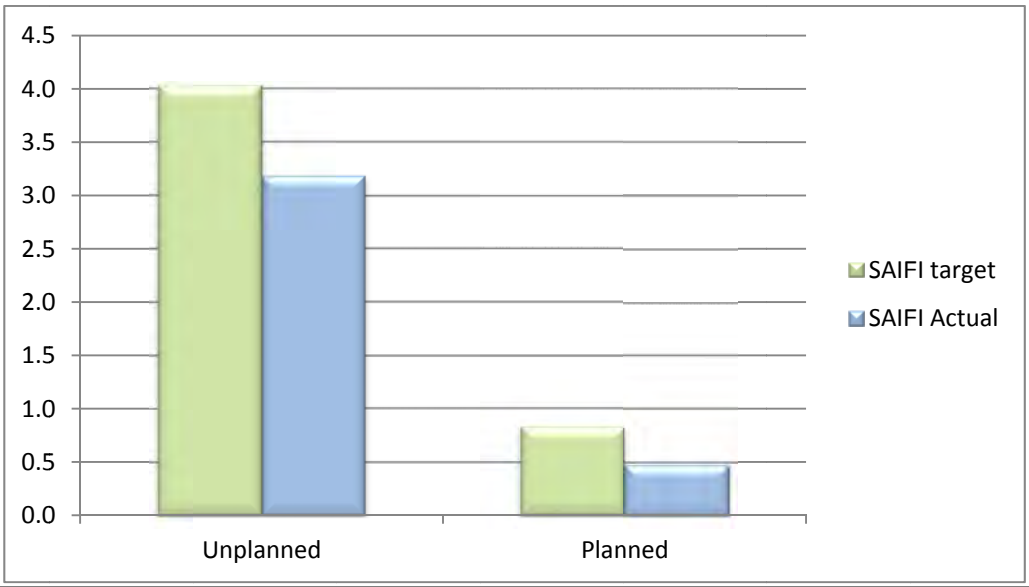
- Urban A – Extreme wind conditions in June 2010 caused a major fault on the Lake Taupo 33kV. The fault contributed 49.09 SAIDI minutes to Urban A's total SAIDI.
- Rural C – There are three reasons for high SAIDI in Rural C, the first being a truck versus pole on the Otorohanga 11kV feeder; this was the largest outage in this service level and it contributed 3.2 SAIDI to Rural C's total SAIDI. The second reason being a faulty batch of insulators caused four major outages on the Mokai 11kV feeder, the fault contributed 7.69 SAIDI to Rural C's total SAIDI. The third reason being an extensive line renewal programme was carried out on the Rangipo/Hautu 11kV feeder; the line renewal contributed 5.52 SAIDI to Rural C's total SAIDI.

8.2.1.1.2 Actions Being Taken to Address the Variances

TLC's on-going objective is to continue to target the rural service level regions through the planning period. A number of urban areas are also being targeted for switch automation. A number of events that have affected CBDs occurred when staff were all away from the urban areas working on rural lines. It can take an extended time to mobilise back into the urban areas and, as a consequence, CBD areas were without supply for some time. This had an effect on the time to restore supply criteria discussed in Section 8.2.1.3 below.

8.2.1.2 SAIFI Performance

Table 8.6 lists the total SAIFI performance for the 2010/11 year. Column 3 lists the variance for the 2010/11 year.



SAIFI Target	4.03	0.83	**TOTAL 4.86**
SAIFI Actual	3.19	0.48	**TOTAL 3.67**
Variance	-21% (F)	-42% (F)	**TOTAL -24.0%** (F)

TABLE 8.6: SAIFI PERFORMANCE FOR 2010/11 AND COMPARISON OF 2010/11 TO TARGET

8.2.1.2.1 Explanation of Significant Variances

The SAIFI performance was better than the targets. There were less unplanned interruptions than anticipated thus indicating a more reliable network.

8.2.1.2.2 Actions Being Taken to Address Variances

TLC's on-going renewal programme will continue to improve SAIFI performance at the individual service level regions and overall levels.

SAIFI values will be affected by the renewal programme in that outages will be needed for renewals to occur. The use of generators to reduce SAIDI often does not have a significant effect on SAIFI given that a short outage is often needed to disconnect and reconnect from the existing line.

It is also more difficult to reduce SAIFI than SAIDI in urban and rural areas when switching and back feeds that cannot be paralleled are used to restore supply. The key to the long-term control of the indices is an effective renewal and maintenance programme.

8.2.1.3 Time to Restore Supply

The customer agreed time to restore supply and the performance targets for achieving this, the actual performance and the variances from targets are listed in table 8.7. (See Section 4 for details on the service level areas.)

MAXIMIUM. TIME TO RESTORE SUPPLY AFTER AN UNPLANNED OUTAGE (HOURS)						
Service Level Region	**Number of Asset Groups**	**Target Time (Hrs)**	**Total Number of Unplanned Events**	**Number of Events Where Target Time Were Not Met**	**Target % (Section 4 table 4.5)**	**Actual Performance**
Urban A	90	3	132	17	95.0%	87.1%
Rural B	17	6	46	1	90.0%	97.8%
Rural C	57	6	224	15	90.0%	93.3%
Rural D	129	6	364	31	90.0%	91.5%
Remote Rural E	22	12	73	4	90.0%	94.5%
Remote Rural F	17	12	91	1	90.0%	98.9%

TABLE 8.7: PERFORMANCE TARGETS AND VARIANCES TO RESTORE SUPPLY AFTER AN UNPLANNED OUTAGE

8.2.1.3.1 Explanation of Significant Variances

The most significant variances occurred in the urban areas. There were three reasons for this listed below:

a) Motor accidents in urban areas that required extensive repairs. It took time to mobilise the resources for these, and;
b) Extreme weather conditions significantly delayed the restoration of supply.
c) Faults in urban areas occurring when staff are working on rural renewal. It takes time for them to mobilise back into urban areas.

The remaining service level performance was better than the performance targets. All service levels have improved compared to financial year 2009/2010.

8.2.1.3.2 Actions Being Taken to Address Variances

There are a number of actions being taken to address and reduce the time to restore supply in urban areas. These are:

- Additional switchgear is being deployed into these areas as a by-product of the hazard control programme. This will allow many of the “daisy chained” transformers to be isolated without causing extended outages when one section of the cable fails.
- Additional staff are being trained in cable jointing and cabling systems.
- Additional training is taking place on the use of generator by-pass.
- Further automation is being deployed into these areas, i.e. automation of a number of key ring main sites.
- As part of the 2011/2012 programme, mobile capacitor banks are being set up to increase the capacity of back feeds.

The control systems in TLC’s emergency generators are also being improved to allow easier connection and operation.

8.2.1.4 Number of Planned Shutdowns per Year

The customer agreed number of planned shutdowns and the performance targets for achieving this, the actual performance and the variances from targets are listed in Table 8.8. (See section 4 for details on service level areas.)

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF PLANNED SHUTDOWNS PER YEAR					
Service Level Region	**Number of Asset Groups per Service Level**	**Target number of shutdowns**	**Number of asset groups where target exceeded**	**Targeted Compliance**	**Actual Compliance**
Urban A	90	2	6	95%	93%
Rural B	17	4	1	90%	94%
Rural C	59	6	5	90%	92%
Rural D	130	6	4	90%	97%
Remote Rural E	22	8	0	90%	100%
Remote Rural F	17	10	0	90%	100%

TABLE 8.8: PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF PLANNED SHUTDOWNS PER YEAR

8.2.1.4.1 Explanation of Significant Variances

The variances were within expected levels. Only the Urban A region was marginally below target; 6 out of 90 asset groups had more than 2 planned shutdowns.

The reasons for these were:

- An extensive line renewal project in the Turangi area (Lake Taupo 33kV line). Due to the complexity of this job 2 short shutdowns were required to synchronise the generator truck on and off the network.
- An extensive line renewal project in the Te Kuiti area (Waitomo Feeder). Due to the complexity of this job 4 shutdowns were required to complete this work.
- An Extensive pole replacement programme was carried out in the Ohakune area (Turoa Feeder). Due to the nature of the work 4 shutdowns were required to complete this work.

In the future, it is likely that this target will have to be varied to accommodate more de-energised renewal work; given that need to complete renewal work at the lowest possible cost.

8.2.1.4.2 Actions Being Taken to Address Variances

There are several actions being taken to maintain the number of shutdowns per year within acceptable limits. It must be remembered that outages are often required to allow the renewal programmes to take place. The actions include:

- More detailed monitoring of outage applications from contractors. This has become less complex now that the new outage reporting system has been fully implemented.
- Use of by-pass generators and mobile capacitor banks to increase the capacity of back feeds.
- Encouraging contractors to develop cost effective live line techniques that can be used in remote rugged country.
- Ensuring contractors and controllers co-ordinate work and planned outages.

8.2.1.5 Number of Short and Long Faults per Year

The customer agreed number of short and long faults and the performance targets for achieving this, the actual performance and the variances from target are listed in table 8.9. (See Section 4 for details on service level areas and how these relate to asset groups.)

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF SHORT AND LONG FAULTS PER YEAR						
	Urban A	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Number of Asset Groups	90	17	59	130	22	17
Target Max number of Long Faults	5	15	15	15	25	25
Number of Asset Groups that did not meet criteria	5	0	0	2	0	0
Target	**95%**	**90%**	**90%**	**90%**	**90%**	**90%**
Actual Performance	94%	100%	100%	98%	100%	100%
Target Max number of Short Faults	20	20	60	60	60	160
Number of Asset Groups that did not meet criteria	0	1	0	0	0	0
Target	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**
Actual Performance	100%	95%	100%	100%	100%	100%

TABLE 8.9: PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF SHORT AND LONG FAULTS PER YEAR

8.2.1.5.1 Explanation of Significant Variances

Urban A long fault performance is marginally below the target. Extreme weather conditions in September and October caused a number of faults in the Ohakune and Maihiihi areas. Other faults in the Maihiihi area were caused by wildlife such as birds coming in contact with electrical equipment.

In the above performance the effect on downstream network has not been included.

8.2.1.5.2 Action Being Taken to Address the Variances

The numbers of faults affecting particular areas are monitored daily. When an event occurs, effort is put into tracking down the actual cause of the faults. This will often involve downloads of protection and ground and helicopter patrols. Tools such as ultrasonic discharge testers and corona cameras are often used to assist with this process.

Other more general strategies to address this include:

- The hazard control programme where a by-product is the introduction of more switching points in underground cabling systems.
- The automation and line renewal programmes.
- The Service Provider has restructured and additional faults staff has been added to rosters.
- Feeder open points have been adjusted, and automated, in a few locations.

8.2.2 Consumer Oriented Performance Targets – Service Related

8.2.2.1 Telephone Calls Coming In to the Organisation and Unanswered Calls

Table 8.10 lists the targeted numbers of telephone calls coming into the organisation and the number of unanswered calls. These are compared to the actual.

COMPARISON OF ACTUAL TELEPHONE CALLS AND UNANSWERED CALLS AGAINST TARGETS							
Item	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Target**	**Variation**
Number of Incoming calls	6155	5260	3119	3785	4098	**4500**	-8.93% (F)
Number of Unanswered calls	816	534	67	336	238	**135**	76.30% (U)
Note : The numbers represent average per month							

TABLE 8.10: COMPARISON OF ACTUAL TELEPHONE CALLS AND UNANSWERED CALLS AGAINST TARGETS

8.2.2.1.1 Explanation of Significant Variances

The monthly average calls overall were below the target of 4500. The number of unanswered calls was above the target of 135. More detailed analysis is shown in Table 8.10a.

FURTHER DETAIL ON INCOMING TELEPHONE CALLS						
Month	**Total number of Calls**	**No Answer**	**Busy Signal**	**Short Duration**	**Total Unanswered Calls**	**Percent Unanswered**
April	3568	13	0	12	25	0.70%
May	4611	12	0	20	32	0.69%
June	6731	46	1303	26	1375	20.43%
July	3713	8	34	12	54	1.45%
August	3831	9	18	14	41	1.07%
September	3950	10	2	15	27	0.68%
October	4689	14	12	19	45	0.96%
November	3651	12	71	19	102	2.76%
December	3223	19	0	15	34	1.05%
January	3684	45	614	21	680	18.46%
February	3319	14	0	13	27	0.81%
March	4210	329	65	18	412	9.79%

TABLE 8.10A: FURTHER DETAIL ON INCOMING TELEPHONE CALLS

Higher numbers of unanswered calls occurred in months where Network or Transpower faults affected widespread areas. At these times the telephone system was overloaded and a large number of busy signals were received by customers. The average number of unanswered calls per month where the <3% target was achieved was 43.

8.2.2.1.2 Action Being Taken to Address the Variances

There were no significant variances from targets for the total numbers of calls. TLC plans to continue improvements to the Zeacom telephone system in the next financial year. The telephone system will allow easier global messaging on the telephone system when major events take place as well as help reduce unanswered calls during peak periods. Modifications to the 0800 number have meant a large number of simultaneous calls can be received and access the global messaging service, reducing the number of busy signals received.

8.2.2.2 Unresolved Complaints: Focus Group Meetings: Customer Clinics

Table 8.11 lists the targets and numbers of maximum unresolved complaints annually investigated by the Electricity and Gas Complaints Commission (EGCC), the industry's complaints resolution organisation, focus groups and customer clinics. Targets are compared to actual.

COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS AGAINST TARGETS							
Item	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Target**	**Variance**
Unresolved Complaints	5	9	2	33	40	**5**	700% (U)
Focus Group Meetings	4	4	4	5	11	**5**	120% (F)
Customer Clinics	16	25	36	30	26	**12**	117% (F)

TABLE 8.11: COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS

8.2.2.2.1 Explanation of Variances

Unresolved Complaints – Unresolved complaints exceeded expectations for three reasons

i. A high number of complaints were associated with landowner and tenant issues. The landowners of installations that are connected to the TLC network are ultimately responsible for the line charges.
ii. The TLC policy of direct billing and billing on load continues to cause confusion throughout the customer base. The difference between meter measured load and formula loads has contributed to this confusion.
iii. There was a negative public relations campaign run by a group of customers.

Focus Group Meetings – This is above target and resulted as a consequence to customers' queries regarding TLC's pricing methodology and landlord/tenant and vacant installation billing issues.

Customer Clinics – There were more customer clinics than targeted.

8.2.2.2.2 Action Being Taken to Address the Variances

TLC has now established a complaint tracking and recording system, which will assist all TLC departments manage their customer complaint workload. This will prevent complaints going through to the EGCC due to slow response times and lack of action.

During recent customer consultation meetings the unequal charging issues was raised; the Board has committed to rolling out suitable communications enabled Time of use meters to all customers by 2015. (Ensuring the metering technology is proven may delay this date.) This will ensure that all customers are charged the same way.

A communications manager has been appointed to ensure customers understand TLC charging. Communication to customers around the TLC policy of billing has already re-commenced. The "why" is being clearly explained through newsletters, advertising and community meetings. Direct communication with customers around TLC policies also plays a large part of the process to resolve complaints.

8.2.3 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and the Efficiency of Line Business Activity

8.2.3.1 Asset Performance Targets

8.2.3.1.1 Asset Performance Targets: Quality: Voltages

Table 8.12a lists the quality performance targets and compares them to actual performance.

COMPARISON OF VOLTAGE PERFORMANCE ACTUALS AND TARGETS							
Item	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Target**	**Variance**
Voltage Complaints	1	1	2	4	10	**10**	0%
Legacy Voltage Issues	1	1	3	1	1	**2**	-50% (F)

TABLE 8.12A: ASSET PERFORMANCE: COMPARISON OF QUALITY TARGETS VERSUS ACTUALS

8.2.3.1.1.1 Explanation of Significant Variances

The variances were within expectations. The voltage complaints were slightly higher than expected but the complaints did not exceed the target.

The 2010/11 plan was to install two voltage regulators to overcome these problems. Due to lack of technical resource and the complexity of the task only one legacy voltage issue was eliminated by year end. The unfinished work was rolled over into the 2011/12 year. The need to target legacy voltage issues is on-going and one of the drivers behind network constraints and load controller settings.

8.2.3.1.1.2 Actions Being Taken to Address the Variances

The voltage levels within the network are constantly monitored and short and long term issues are followed up. Short term issues tend to be addressed by adjustments to equipment including regulators and tap settings. The long term issues tend to be identified by network analysis and improved strategies that are included in this plan. Monitoring of voltage equipment via SCADA has also been increased as part of improvements to customer service and compliance.

8.2.3.1.2 Asset Performance: Harmonic Levels

Table 8.12b lists the quality performance targets and compares them to actual performance.

HARMONIC DISTORTION: ACTUALS AND TARGETS				
System	**Description**	**2008/09**	**2009/10**	**2010/11**
Harmonic Levels 3-Wire Systems **Target is 10%**	Measured Sites	143	143	171
	Instance where target exceeded	11.19%	11.19%	8.19%
Harmonic Levels SWER Systems **Target is 30%**	Measured Sites	66	66	21
	Instance where target exceeded	3.03%	3.03%	9.25%

TABLE 8.12B: ASSET PERFORMANCE: HARMONIC DISTORTION TARGETS AND ACTUAL

Table 8.12b lists the number of measurements taken for harmonic distortion and percentage of measurements where the levels have exceeded the targets. The objective of this performance target is to monitor the level from year to year, and ensure that levels are stable.

8.2.3.1.2.1 Explanation of Variances

a) The Southern 33 kV system variances were caused by light loading, downstream SWER feeders, ski field operations and long cable lengths.

b) Southern 11 kV system variances were caused by industrial loads with high numbers of variable speed drives.

c) The Southern SWER system variances were caused by light loadings and the amplification effect of SWER systems.

8.2.3.1.2.2 Action Being Taken to Address Variances

Harmonics are likely to increase as more power electronic equipment is connected to existing and new connections. TLC's terms and conditions of supply and connection standards control existing and new connections. Variances in the levels of harmonics (and voltage flicker) will be controlled by these standards being tightened.

The variances in the SWER systems have to be closely monitored. TLC has concerns about the effects of electronic light bulbs and heat pumps on harmonic levels of SWER systems.

8.2.3.1.3 Asset Performance: Surges That Cause Destruction of Electronic Equipment

Table 8.13 lists the voltage surge performance targets and compares them to actual performance. (These are measured from the number of complaints and resulting insurance claim letters).

VOLTAGE SURGE PERFORMANCE ACTUALS AND TARGET			
	Actual	**Target**	**Variance**
Number of surge events (Measured and compared to numbers of customers)	38	**80**	-53% (F)

TABLE 8.13: VOLTAGE SURGE PERFORMANCE

8.2.3.1.3.1 Explanation of Variances

There were fewer incidents and complaints from customers than the target.

8.2.3.1.3.2 Actions being taken to address variances and voltage surges

The level of variance was below target levels. TLC is taking the following actions to reduce the impact of surges:

a) Surge suppression devices are being fitted throughout the network at a relatively low break-over voltage.
b) TLC is encouraging customers to install surge protection in their installations. This includes free giveaways to promote a demand site management approach.
c) TLC uses engineering techniques and design criteria to ensure suppression devices are installed. For example, cabling is used between substation transformers and feeders with arrestors fitted.

8.2.3.1.4 System Component Performance: Failures

Table 8.14 lists the system component performance failure targets and compares these to actual performance.

COMPONENT PERFORMANCE FAILURE ACTUALS AND TARGET								
Item	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Target**	**Variance**
Component Failures	178	188	219	271	295	290	**254**	14.17% (U)

TABLE 8.14: COMPARISON OF SYSTEM COMPONENT PERFORMANCE: FAILURES VERSUS TARGETS

8.2.3.1.4.1 Explanation of Variances

The system component failure performance was higher than the target by 14.17%. Extreme weather conditions in September and October caused a number of component failures; these were mainly overhead lines and old deteriorating fuse problems. A faulty batch of insulators also contributed to the total number of failed components. The overall system component failure performance was marginally better than last year.

8.2.3.1.4.2 Actions Being Taken to Address the Variances

TLC has a renewal programme in place that over the long term will address component failures due to age. TLC is continuing with a strategy of trying to follow up fault “warning signs” (such as auto recloses) before situations deteriorate to failure and renew assets that are in poor condition. TLC is very focused on the quality of components that are used on the network.

8.2.3.1.5 Environmental Performance

Table 8.15 lists the environmental targets and compares these with the performance.

COMPARISON OF ACTUAL VERSUS TARGET ENVIRONMENTAL PERFORMANCE			
2010/11	**Actual**	**Target**	**Variance**
Prosecution or Abatement Notices	0	**0**	0%
Environmental Improvement Works Completed	0	**0**	0%

TABLE 8.15: COMPARISON OF ACTUAL VERSUS TARGET ENVIRONMENTAL PERFORMANCE

8.2.3.1.5.1 Explanation of Variances

There are no variances in the targeted performance. Environmental work is prioritised and completed within planned schedules. (There was no work included in the 2010/11 year).

8.2.3.1.5.2 Actions Being Taken to Address the Variances

A review of environmental compliance also took place. This review identified the need to continue with the strategies within this Plan to mitigate environmental risks. TLC has assets that do need environmental enhancements and these are included in forward Plans.

8.2.3.2 Asset Efficiency Targets

8.2.3.2.1 Network Losses

Table 8.16 lists the technical loss targets by regions and the actual losses as confirmed by network studies based on system loads. (Heavy and light load).

COMPARISON OF TECHNICAL LOSS STUDIES BASED ON NETWORK REGION										
Region	**2008/09**		**2009/10**		**2010/11**		**Target**		**Variance**	
	Heavy	*Light*	*Heavy*	*Light*	*Heavy*	*Light*	***Heavy***	***Light***	*Heavy*	*Light*
North	6.65%	1.74%	6.65%	1.74%	5.13%	1.29%	**7.00%**	**2.00%**	-1.87% (F)	-0.71% (F)
Central	6.14%	4.91%	6.20%	5.00%	10.39%	1.84%	**8.00%**	**5.00%**	2.39% (U)	-3.16% (F)
Ohakune	4.66%	1.05%	4.70%	1.10%	13.37%	1.57%	**9.00%**	**2.00%**	4.37% (U)	-0.43% (F)

TABLE 8.16: COMPARISON OF TECHNICAL LOSS STUDIES BASED ON NETWORK REGION

8.2.3.2.1.1 Explanation of Significant Variances

The technical losses at light loads are below the target and technical losses at heavy loads are marginally above the target in the Central and Ohakune areas. This is being driven by the strategy to increase capacity at the lowest possible cost; mostly through the increased use of regulators instead of increasing conductor sizes and voltages. The level of distributed generation including the related reactive power flows affects the central areas losses.

8.2.3.2.1.2 Action Being Taken to Address the Variances

Setting loss targets is difficult due to the variability that comes about with run of river hydro distributed generation connections. Rain can make a significant difference to the operation of the plant. Overall loss targets (not included in Table 8.16) are also significantly affected by non-technical losses caused by metering, meter reading and data processing errors.

Long term, TLC is focusing on reducing losses by:

- Demand site management initiatives by the use of load control systems and charges.
- Reducing retailer errors by making them aware of the issues and upgrading the metering technology to be able to produce demand data.
- Designing to minimise losses.
- Requiring distributed generators to set plants to minimise losses and maximise power factor during RCPD periods.
- More innovative load control and network automation schemes.
- When necessary and practical, deployment of capacitors to reduce reactive power flows. (Our preference however would be for this to be done by demand side initiatives).
- In the case of Ohakune; upgrading the network and establishing the Tangiwai point of supply.

8.2.3.3 Network Power Factor

Table 8.17 lists the target power factor average by Grid Exit Point (GXP) during RCPD periods and the actual performance as calculated from the national dataset that is available from the Electricity Commission.

COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL			
Grid Exit	**Actual Power Factor**	**Power Factor Target**	**Variance**
Hangatiki	0.909	0.912	-0.33% (U)
Ongarue	0.851	0.916	-7.10% (U)
Tokaanu	0.995	0.992	0.30% (F)
National Park	0.994	0.990	0.40% (F)
Ohakune	0.993	0.991	0.20% (F)

TABLE 8.17: COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL

Note: The Ohakune grid exit is shared with Powerco as discussed in other sections.

8.2.3.3.1 Explanation of Significant Variances

The target is to hold power factors at present levels. The distributed generation injections at Hangatiki and Ongarue GXP are lowering the power factor at the sites. There has been an additional two distributed generators connected to Hangatiki in the past period that appear to have lowered the area power factor. The Ongarue power factor appears to have been lowered by a combination of events associated with both the generation and load. (See Section 5 for further explanation on effects of distributed generation on power factor.)

8.2.3.3.2 Actions Being Taken to Address Variances

As outlined in Section 5, distributed generation reduces grid exit power factor unless plant is injecting reasonably large amounts of reactive power during RCPD periods. This is often not possible due to network voltage levels and the types of machines being used.

It is possible to also show that it is not the RCPD power factor figure the connection code should be focused on but rather the amount of reactive power during RCPD periods. As a consequence of this, TLC has applied to Transpower, and has been granted, an exemption from power factor during RCPD periods for the Hangatiki GXP. Transpower has granted this request via a variation agreement.

At a local level TLC is using its network models and working with generators to better adjust equipment to improve the RCPD power factor and to minimise losses. This is a relatively complex and time consuming process but can substantially improve power factor and reduce losses. (Improved generator power factor has a flow on effect in that network voltages can become excessively high during light load periods).

8.2.3.4 Network Load Factor

Table 8.18 lists the target load factor and compares this with the actual for the 2010/11 year.

COMPARISON OF LOAD FACTOR TARGETS AND ACTUAL			
	Actual	**Target**	**Variance**
Overall Network Load Factor	59.00%	**60.00%**	-1.67% (F)

TABLE 8.18: COMPARISON OF LOAD FACTOR TARGETS AND ACTUAL

NETWORK LOAD FACTOR ACTUAL			
Financial Year	**Electricity Volumes Carried (MWhr)**	**Co-incident System Peak (MW)**	**Load Factor**
2004/2005	314.6	55.6	64.61%
2005/2006	317.6	55.7	65.09%
2006/2007	329.5	58.4	64.35%
2007/2008	327.0	65.0	57.00%
2008/2009	319.0	61.0	60.00%
2009/2010	354.0	64.0	64.00%
2010/2011	323.0	63.0	59.00%

TABLE 8.18B: NETWORK LOAD FACTOR ACTUAL

8.2.3.4.1 Explanation of Variances

The load factor is lower than the target. The total energy and maximum co-incident demand is also lower than the previous year.

8.2.3.4.2 Actions Being Taken to Address Variances

A high load factor means that assets are being well utilised. There can be some conflict between this and the loss target depending on network dynamics. The load factor is seen as an important network effectiveness indicator and the long term objective of demand charging is to improve the load factor over time. It does vary from year to year and there are many factors that cause this.

8.2.3.5 Asset Effectiveness Targets

8.2.3.5.1 Accidents/Incidents Involving TLC Network Assets

Table 8.19 compares the targets to the actual.

ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET				
Event	**Actual 2009/10**	**Actual 2010/11**	**Target**	**Variance**
Lost time - injuries involving Staff or Contractors	18	6	**5**	20% (U)
Average hours lost (per employee)	1.42	1.32	**<2.5**	-47% (F)
Number of DoL notifiable accidents	0	0	**0**	0%
Number of public injuries involving a TLC facility	0	0	**0**	0%

TABLE 8.19: ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET

8.2.3.5.1.1 Explanation of Significant Variances

The number of lost time injuries was marginally ahead of the target. 2010/2011 performance has improved significantly compared to the previous year due to better hazard control. The other indices: average hours lost per employee, OSH notifiable accidents and the numbers of public injuries involving a TLC facility were below the target.

8.2.3.5.1.2 Actions Being Taken to Address the Variances

The following actions are being taken to minimise accidents/incidents involving TLC assets and ensure they are performing below target levels:

- Hazard control is priority for all asset planning and designs.
- Assets inspected and the likelihood of them creating hazards is assessed.
- Hazard control renewal programme underway.
- Strong hazard control policies in place with clear non-negotiable criteria.
- Extensive control room and other hazard control systems and policies.
- Regular work crew auditing and feed back.
- On-going asset patrol and inspection programmes in place.
- Formal staff hazard awareness programme put in place.

8.2.3.5.2 Number of Asset Hazards that are Eliminated /Minimised Annually

Table 8.20 compares the target numbers of asset hazards that are eliminated/minimised as compared to actual.

ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET			
Hazard Category	**Actual 2010/11**	**Target 2010/11**	**Variance**
Pillar Boxes	44	**50**	-12.00% (U)
Two Pole Structures	8	**8**	0.00%
Ground Mount Transformer	2	**2**	0.00%
Switching equipment	3	**3**	0.00%
Total Hazard Control	57	**63**	-9.52% (U)

TABLE 8.20: ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET

8.2.3.5.2.1 Explanation of Significant Variances

All hazard elimination/minimisation projects excluding the pillar box renewal were completed. The pillar box renewals fell short of its target due to difficulties within the contracting job management systems. Resources were diverted to other projects such as fault repairs.

8.2.3.5.2.2 Actions Being Taken to Address the Variances

Continuous improvement of the work management systems is taking place to ensure focus throughout the year is maintained on priority hazard renewals. (Faults, customer demands and the need to complete other priority emergent work can quickly take the focus away).

The intellectual experience of the contracting team is gaining a greater understanding of the need to resource for the amount of work they have in front of them.

8.2.3.5.3 Diversity Factor

Table 8.21 compares the target to the actual.

DIVERSITY FACTOR: ACTUAL COMPARED TO TARGET					
	2008/09	**2009/10**	**2010/11**	**Target**	**Variance**
Ratio	1.54	1.59	1.63	**1.56**	4.31% (F)

TABLE 8.21: DIVERSITY FACTOR: ACTUAL COMPARED TO TARGET

8.2.3.5.3.1 Explanation of Variances

The performance is higher than the target, which indicates an improved network performance.

8.2.3.5.3.2 Action Being Taken to Address the Variances

This is a benchmark target that has been set to measure the level of asset utilisation. Analysis and reporting work is being carried out to ensure that this ratio is consistent at both individual transformer level, and by segments, asset groups and billing density. Transformers that are incorrectly sized, i.e. customers who are not being fairly charged for their network capacity and demands, are identified. This work will create a stable ratio and target.

Note: The target ratio will have to be adjusted if the spread of the demands averaged for individual customers is changed in any review of the billing system.

8.2.3.5.4 Ratio of Total Number of Trees Felled to Trees Worked on Annually

Table 8.22 lists the actual annual ratio of the numbers of trees felled to the numbers of trees worked on.

RATIO OF TREES FELLED TO TREES WORKED ON							
	2006/07	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**Target**	**Variance**
Ratio of the Number of Trees Felled to Number Of Trees Worked On	71.00%	75.00%	73.00%	79%	80%	**70.00%**	14.29% (F)

TABLE 8.22: COMPARISON OF THE RATIO OF TREES FELLED TO TREES WORKED ON

8.2.3.5.4.1 Explanation of Variances

The variation was within expectations. The 2010/11 fell rate was above target due to a large number of trees being removed from plantation areas. Customers' understanding of the importance of allowing trees close to power lines to be removed to improve reliability and minimise costs is increasing.

8.2.3.5.4.2 Actions Being Taken to Address the Variances

TLC is constantly striving to increase the fell rate to try and minimise its long term vegetation control costs and improve reliability.

8.2.3.6 Line Business Activity Efficiency Targets

The line business activity efficiency targets are based on the 31st October 2008 Electricity Distribution (Information Disclosure) Requirements 2008. The data and information requirements needed to establish these targets and measure against them have taken a little time to understand and develop.

Table 8.23 lists the 2010/11 lines business activity efficiency targets and the actual performance achieved against them.

DISCLOSED PERFORMANCE INDICES ACTUAL VERSUS TARGET		
Description	**2010/11 Actual**	**2010/11 Target**
Operational Expenditure Ratio	1.98%	2.01%
Capital Expenditure Ratio	1.84%	2.00%
Capital Expenditure Growth Ratio (Factor)	$215	$149
Distribution Capacity Utilisation Factor	27%	28.00%
Return on Investment	9.33%	6.00%
Capital Expenditure per Total Circuit Length	$1,429	$1,813
Capital Expenditure per Electricity Supplied to Customers Connection Points	$24	$22
Capital Expenditure per Maximum Co-Incident System Demand	$113,449	$124,752
Capital Expenditure per ICP	$292	$327
Capital Expenditure per Distribution Transformer Capacity	$40	$37
Operational Expenditure per Total Circuit Length	$1,388	$607
Operational Expenditure per Electricity Supplied to Customers Connection Points	$23	$7
Operational Expenditure per Maximum Co-Incident System Demand	$110,190	$41,762
Operational Expenditure per ICP	$284	$109
Operational Expenditure per Distribution Transformer Capacity	$14	$12
Interruption Targets Class B (Planned) for planning period.	300	331
Interruption Targets Class C (Unplanned) for planning period.	863	800
Faults per 100km for 11 kV non SWER	33.1	35
Faults per 100km for 11 kV SWER	0.5	0.7
Faults per 100km for 33 kV	2.2	3.3
Overall Reliability (SAIDI)	296.91	300
Class B Reliability (SAIDI Planned)	68.07	97
Class C Reliability (SAIDI Unplanned)	228.84	203

TABLE 8.23: 2010/11 DISCLOSED PERFORMANCE INDICES ACTUAL VERSUS TARGET

8.2.3.6.1 Explanation of Significant Variances

The following business activity efficiencies were within target:

- Capex growth ratio
- Return on investment
- Capex per electricity supplied to customer connection point
- Capex per co-incident system demand
- Capex per distribution transformer capacity
- Opex per total circuit length
- Opex per Electricity supplied to customer connection point
- Opex per co-incident system demand
- Opex per ICP
- Opex per distribution transformer capacity
- Planned Interruption – Class B
- Overall SAIDI
- Planned SAIDI Class B.

The remainder of the business activity efficiencies were below and above targets. The principal reason for this was that the 2010/11 target was set based on data that were not as robust as current data and errors in allocation were found once the new outage reporting system was put in place.

There is also some confusion industry wide on the definitions of the indices behind the criteria. A key aspect of this is the interface between the accounting and asset management systems. Development of the interface is on-going. The Commerce Commission has also recognised this indices comparison difficulty and has just released a draft consultation paper to give further clarity on the measurements.

8.2.3.6.1.1 Actions Being Taken to Address the Variances

Data System

A new data system has been put in and greater focus has been put on procedures and policies to improve the accuracy of entered data. The actions being taken to address this include the on-going investment in the system to continually develop and expand the data held. The work includes making the system more user friendly. Also in parallel with this development the intellectual understanding of staff is continually being progressed.

The Number of Faults on 11 kV Lines

The renewal programme is focused on bringing all lines, including 11 kV lines, up to a performance level that aligns with the criteria in Section 4.

8.3 Gap Analysis and Identification of Improvement Initiatives

8.3.1 Significant Gaps between Targeted and Actual Performance

8.3.1.1 Financial CAPEX Expenditure Performance

Capex performance overall, on a project by project basis, was within estimate expectations. Variations occurred on specific projects due to a host of factors; these varied from issues revealed once more detailed design was done through to landowner and access issues. Many of these factors are difficult to control given the realities of the remote, rugged rural environment and TLC's limited resources; things have to change from time to time and TLC does not have large numbers of people to put into exhaustive planning.

The most significant controllable factors that are causing a gap in performance are:

i. The budgeting process up to the 2012/13 year was controlled by approximately 420 interlinked spread-sheets. Due to the detail in preparing this Plan the maze was complex and errors often occurred when minor changes were made. The Basix system was designed to take over this function and eliminate these errors by calculating forward estimates in a limited and controlled manner.
ii. Data for the reported spends were of higher accuracy than in previous years. Further work is required to improve the process and make compiling the plan less labour intense. This gap in performance is being worked on by researching and looking at ways to better integrate the job costing system and Basix. This will probably see more of the job costing functions transferred to Basix over time.
iii. A number of projects have had a delayed starting time due to lack of resources, which includes both labour and material. This results in some of the projects rolling between years. TLC is continually balancing costs against resources. The way forward to control this gap in performance is to automate as much of the planning as possible through the use of tools such as Basix. Planning tools are available in Basix and an individual with the knowledge to develop this has recently been employed. It will take time to develop this further using a continuous improvement approach.
iv. Line renewal expenditure is difficult to predict until the specific line detail is captured. This is done as part of the 15 yearly inspection process and until the cycle is completed there will be a variation between the forward estimates and the actual needs once a detailed inspection has taken place. Performance to date, however, has shown that the bottom line has remained relatively constant and as estimated.
v. TLC's network capacity is being pushed to allowable equipment ratings in some places. Any perturbation in customer development can quickly cause a need for further cumulative upstream network investment. This causes a gap in performance, and the need to modify the network rapidly to provide capacity is being managed through the use of the network analysis tool and work in developing load predictions. Demand billing is also seen as a way forward to minimise this gap.

The capital expenditure is a significant driver of forward revenue requirements. Research and evaluation to date provides evidence that the work is needed. The major challenge for TLC is to complete this work at a lower cost.

Analysis of capital expenditure shows that about 30% of the cost is materials and the remaining 60% is labour and plant. Live line and generator by-pass work are about 50% more expensive than de-energised work methods in terms of labour and plant.

Customers often complain about prices and shutdowns for maintenance and renewal. A key part of TLC's forward strategy is to make customers aware of this issue trade-off and if necessary apply for a customised quality path.

This will include things such as public relations, customer consultation and development of the asset management systems to provide customised customer information, for example the outage notification will need to be tailored for customer notification letters, texts and emails.

8.3.1.2 Maintenance Expenditure Performance

Maintenance expenditure overall was about 13% lower than estimates. The subcategories (see Table 8.3) all tracked relatively close to estimates. There were some gaps in individual items, however, as discussed in 8.3.1 above where it is thought that many of these gaps in the performance have come about due to reporting problems in the job costing systems. Overall, the direct maintenance activities followed the plans and policies in Section 6.

Indirect maintenance work followed a similar pattern with all but the allowances for consultants tracking close to estimates. Savings were made by employing less external advice than estimated.

8.3.1.3 SAIDI Performance by Service Levels

Overall SAIDI performance was slightly below target. There were some small variances between targets and performances. The on-going renewal programme is designed, over time, to minimise the gaps between performance and targets.

8.3.1.4 SAIFI Performance: Overall and by Service Levels

As per SAIDI, TLC is concerned that SAIFI may become more difficult to control in rural areas. SAIFI going forward will need to be monitored carefully as its effects on customers can be more significant than SAIDI.

8.3.1.5 Time to Restore Supply

The gap to restore urban areas was greater than expected.

Strategies are included in this Plan to address this (see section 5 and the discussion earlier part of this section). The significant gains are expected to come from automation particularly in urban areas.

Other innovative initiatives such as the use of mobile capacitor banks to increase the capacity of alternative supplies are also being developed.

8.3.1.6 Number of Planned Shutdowns per Year

There were no significant gaps. A difficult and significantly large renewal project in the Turangi area affected the compliance in Urban A service level.

8.3.1.7 Number of Short and Long Faults per Year

Performance for long faults was below target for Urban A service level and performance for short faults was below target for Rural B service level. The main cause was the time to mobilise staff and carry out repairs (see Section 8.2.1.5). Automation improvements in recent plans have been targeting improvements in these areas.

8.3.1.8 Telephone Calls Coming Into Organisation

TLC had some significant performance gaps when it introduced direct and demand billing. These performance indices will be continuously monitored going forward. The renewal programme will minimise the numbers of telephone calls associated with reliability. On-going PR, continuous improvements of the billing system, improved telephone systems and other customer service initiatives are key to ensure this gap is controlled.

8.3.1.9 Unresolved Complaints: Focus Group Meetings: Customer Clinics

Gaps in the unresolved complaints were significant when direct and demand billing was introduced. These indices will have to be monitored carefully going forward, given the amendments to the electricity legislation making landlords responsible for line charges. Unresolved complaints can significantly increase operating costs and resources. Future initiatives will be focused on focus group meetings, customer clinics, and various public relations initiatives. These should help to reduce misunderstandings and dissatisfaction.

8.3.1.10 Quality Voltage and Harmonics

Voltage complaints tracked higher than expected but did not exceed the target. Voltage levels are constantly monitored and analysed. The analysis package has recently been upgraded further and more work will be done during 2012/13 to increase the understanding of voltage levels on some of the remote SWER systems where loadings are higher. SWER systems have different characteristic impedances than 2 and 3 wire systems and this effect can cause greater voltage attenuation than the more conventional systems; understanding these, and how they relate to the actual TLC operating considerations, needs further research.

The Electricity (Safety) Regulations 2010 fine structure places more significance on gaps between statutory limits and operating voltage levels outside of these limits.

8.3.1.11 System Component Performance: Failures – Gap Analysis

The gap between target and actual of system component failures is an on-going point of focus. The gap between target and performance means:

- Continuing focus and recognition of the importance of the renewal programme.
- Continuing research and improvement on the quality of materials, components and work methods used on the network.
- On-going focus on the quality of data being put into the Basix system to ensure that the performance can be consistently measured between years.

The gap reinforces the need for renewal programmes.

8.3.1.12 Environmental Performance

There were no incidents and there is no gap between target and performance.

8.3.1.13 Network Losses

The discrepancies in the network losses are an on-going point of focus. There is a problem with getting consistent information on energy sold to customers from the market. This is beyond TLC's control and is a gap that the industry and market have recognised and are attempting to address through improved registry and other systems.

The winter loads and the need to 'sweat' the Ohakune networks and Central area networks in the ski seasons pushed the losses in these areas higher than expectations. The building of additional capacity into Ohakune will ease this increase in future years.

8.3.1.14 Network Power Factor

The overall network power factors have remained aligned to targets. The low power factors at the grid exits where distributed generation is connected were caused by this equipment. TLC has been granted an exemption from the codes for Hangatiki and other applications will be forwarded when resource is available to prepare and submit these.

8.3.1.15 Network Load Factor

There was a 6% decrease in network load factor as compared to target. This is likely to be driven by the effects of demand billing.

8.3.1.16 Accidents/Incidents Involving TLC Assets

There was a performance gap with the numbers of lost time injuries. This is being closely monitored as it was suspected that the quality of data in the past on which the target was based may have been inaccurate. Additional staff programmes have also been introduced.

8.3.1.17 Number of Hazards that are Eliminated/Minimised Annually

There was no significant performance gap with the number of hazards that are eliminated/minimised annually.

8.3.1.18 Diversity Factor

There was no performance gap with the Diversity Factor. This is a measure that will be monitored closely as time goes on to ensure TLC is recovering appropriate revenue from various network areas.

This index is part of the on-going research and development of understanding on the impact of demand billing.

8.3.1.19 Rate of Total Number of Trees Felled to Trees Worked On Annually

There was no performance gap with the ratio of the total number of trees felled to trees worked on annually.

8.3.1.20 Line Business Activity Efficiency Targets

The line business activity efficiency targets are aligned to the Commerce Commission disclosure requirements. Many of these were implemented in 2005 and were designed for intercompany comparisons. There will be variations among companies for a whole host of reasons including the architecture of the individual networks and how this came about.

The targets have been set based on the expected results, given TLC's current plans. Variances will result when changes to these plans have to be made due to changes in customers, legislations, environmental and data reliability factors.

The major variance between 2010/11 target and actual performance was associated with the numbers of faults on 11 kV/km of line. The reason for this variance was mostly the quality of data, which highlights the need for an on-going focus on data quality and reliability. TLC has been developing an automated database to record this data and has also been developing its intellectual understanding of these needs to ensure that the data are correct.

There is still some way to go and some of the reasons for this are to do with the underlying definitions of the indices behind these data. As outlined earlier in this section work is underway at all industry levels to better define these so that intercompany comparisons can be improved.

8.3.2 Overall Quality of Asset Management and Planning Processes

8.3.2.1 Overview

TLC has been continually striving to improve its AMP. The focus from 2005 to 2009 was to:

- Fully research asset renewal needs.
- Develop accurate network models.
- Develop renewal, development and maintenance plans.
- Improve network data and systems.

The focus of the 2010/11 Plan was to further review future workloads and smooth this to give more stable funding and resource requirements. The 2011/12 Plan review continued to refine the work completed from 2005 to 2010/11.The 2012/13 review focused on the transfer of forward expenditure details from a multitude of spread sheets into the Basix asset management database. There was also a lot of work done on outage reporting and quantifying the accuracy of data and the development of reporting.

Further improvements were also made to the network models and further load prediction modelling to be able to track as accurately as possible the impacts of demand billing.

The 2012/13 review also changed the way that data was presented on planned renewal and development works in an effort to better present these details to stakeholders. A section was removed from the Plan and reintegrated into section 5 and 6.

The network performance objectives are generally being met with few gaps between actual and the details included in the terms and conditions of supply. The renewal, development and maintenance plans will continue to unfold to produce this performance through the planning period. Customers will not tolerate a network that does not meet quality reliability and hazard control expectations. TLC has to focus on renewal of remote rural lines and removal of hazards from the network lines for the next seven years. The 15 year renewal cycle then starts with its second pass.

At an overview level, managing the TLC assets which are old and have hazard control deficiencies, is relatively complex given that the majority of them were constructed to supply electricity to the remote and rugged areas of the King Country. These assets were constructed with government subsidies using low cost methods such as SWER and recycled railway iron poles. Today, customer expectations are much greater than those for which the assets were designed. The government subsidy is no longer available for renewal and the customers have limited ability to pay. The Plan recognises this background and is designed to give the best value for money in a sustainable way whilst meeting a myriad of legislative requirements.

To meet this objective, the Plan will continue to evolve, pushed along by advances in equipment, technology, customers'/stakeholders' expectations, legislative development and the organisation's intellectual knowledge.

As explained in earlier sections, a big focus for TLC in the next period will be to complete capital works in a more effective way that minimises the costs and on-going increase in RAB. The increase in RAB drives the need for more revenue as the value of assets increases.

A whole host of initiatives are planned to address this issue, including some external assistance in reviewing this Plan, a likely Customised Price Path (CPP) application for quality, customer consultation and extensive modelling of the implications for the impact of changes to engineering overheads and work effectiveness.

As demand billing has filtered out to customers many have become increasingly aware of load control and the associated control times. In the future, it is likely that an increased focus will be needed on control times and the impacts of these on customers.

Areas that need further improvement include financial reconciliation, delivery of the projects listed in this Plan in a more effective manner, and the development of further advanced network strategies. Further work is also proposed on the overall identification of works and individual activity strategies. This will be aligned with the evolution of Commerce Commission, Safety Management System, Electricity Legislation and downstream requirements.

TLC believes that, overall, the quality of the asset management and processes are in line with industry best practice.

8.3.2.2 Background and Objectives

The overall quality of the asset management and planning within the business is summarised in the following sections:

8.3.2.2.1 The purpose of the Plan

The purpose is understood, and is described in Section 2. The quality of this understanding will continue to develop.

8.3.2.2.2 The interaction between those objectives and other corporate goals, business planning processes and plans

The Asset Management Plan interacts with corporate goals, business planning processes and plans. As the quality of the AMP has improved and will continue to improve, so has the quality of the interaction and business planning processes. Improvements in the quality of the AMP have added clarity to the business planning options available.

A long term objective/concept is to improve integration between engineering, reliability, quality, development, hazard control and prices. This detail will see continuous improvement in the understanding of the different costs for regions and customer groups.

It is recognised that the asset management systems need further development to be able to translate these costs into more detailed levels of pricing.

8.3.2.2.3 The period covered by the Plan, and the date the Plan was approved by the Board of Directors of the EDB

The focus has been to take the Plan out as far as possible to give stakeholders a clear picture of the network needs into the future. It is recognised that the planning process requires a long term focus. The Directors put considerable thought into the implications and quality of the AMP before approving it. They recognise that considerable effort has to go into the development of the Plan and have to balance this against other organisational needs.

8.3.2.2.4 Stakeholder interests

TLC's stakeholders' interests are considered in the asset management and planning processes. The overall quality of these interests in the asset management and planning processes is considered best industry practice. For example, based on feedback from stakeholders, the separate section listing our future planned works has been modified and reintegrated into section 5 and 6.

8.3.2.2.5 Accountabilities and responsibilities for asset management

The quality of staff accountable and responsible for asset management and planning aligns with industry best practice. The staff who are accountable and responsible are qualified and have many years of industry experience. Directors also pay considerable attention to performance and demand a high level of accountability and responsibility.

8.3.2.2.6 Asset management systems and processes

Some years ago TLC recognised that it needed to improve its asset management systems and processes. It has invested in intellectual knowledge and technology to improve systems. This is an on-going process and includes the integration of information. TLC believes the current quality of these systems aligns with industry best practice. Looking forward, TLC is well down the track via its demand side management and other initiatives to setting up the "next generation" of systems and will, in the near future, have quality that might be considered to set a higher level of capability than industry best practice.

Specifically, the database and system framework will allow more complex and smarter control systems to extend network capability. Plans are in place, and progress will be made in the next few years, to establish a full connectivity model, including all assets utilised down to individual ICP level. The connections from transformers to the low voltage systems are where TLC's database is currently incomplete.

In parallel with this the pricing calculators will also have to become more complex and they will have to be integrated back into the asset management systems.

8.3.2.3 Assets Covered

8.3.2.3.1 High level description of distribution area

The asset management and planning process covers the entire network and includes details of the area covered, large customers, load characteristics and peak demand. The quality of this information is as accurate as possible and comprehensive.

8.3.2.3.2 Network Configuration

The asset management and planning process includes the full description of assets. This description includes a comprehensive amount of key data including general asset types, capacity and physical location. The quality of information has significantly improved and is based on network knowledge, technical information and linked data from TLC's asset systems.

TLC is continuing to develop its asset analysis and databases to better model the network to determine the optimal network configuration. During the 2012/13 year, further modules will be added to the network module to better model 2 phase systems and wind turbines.

8.3.2.3.3 Network assets by category, including age profiles and condition assessment

The asset management and planning process includes the use of information on assets by category, including age profiles and condition assessment. The quality of this information has significantly improved and is extensively linked to data in TLC's asset systems. TLC believes the quality of this now aligns with industry best practice. The last two areas of data uncertainty are now being worked on. These are a connectivity model through the low voltage network i.e. the connection between transformers and individual ICPs and a further breakdown of technical equipment.

8.3.2.3.4 Justification for assets

The asset management and planning process includes consideration of the justification for assets. TLC's pricing and billing strategies sharpen the quality of asset justification considerations. Because TLC has a vast rural area, with a limited amount of customers, funding of assets has to be transparent. Assets have to be justified.

8.3.2.4 Service Levels

8.3.2.4.1 Consumer oriented performance targets

TLC has developed consumer oriented performance targets that use industry indices as a base but expand on these. The objective of these is to make them more focused on what the customer understands and requires. The quality of the data behind these targets has significantly improved and the targets are used in planning and asset management processes.

As time goes on, the levels of these targets will be reviewed and adjusted to ensure they align with customers' expectations. The quality of this process is considered to be industry best practice. TLC will continue to base asset development and renewal on customer related performance. (This will also include integration with other requirements such as the SMS system).

8.3.2.4.2 Targets relating to asset performance, asset efficiency and effectiveness and the efficiency of the line business activity

TLC has developed asset performance efficiency and effectiveness targets. The objectives of these targets are to focus on asset performance and not get side tracked onto specific technical issues. These targets will be reviewed as time progresses. The quality of this process is considered to be continually improving and aligned to industry best practice. It is likely that load control performance targets will be introduced during the next review of the AMP.

8.3.2.4.3 Justification for target levels of service based on customer, legislature, regulatory, stakeholder and other considerations

TLC has developed targets based on performance delivered to the customer and maintained industry comparison targets for regulatory and legislation purposes. The quality of targets and justification for these targets, the quality of data, and related systems is considered to be continually improving and reflective of industry best practice.

8.3.2.5 Network Development Planning

8.3.2.5.1 Planning Criteria and Assumption

The planning criteria and assumptions align with corporate objectives. These will continue to evolve as time goes on and it is believed the overall quality of these fits with TLC's asset management and planning.

8.3.2.5.2 Prioritisation Methodology adopted for development projects

TLC's prioritisation methodology is focused on doing high consequence, high risk development projects first. Many of these relate to hazard control. It is believed that the overall quality of asset management and planning that results from this meets customer, legislative, regulatory and stakeholders' expectations.

8.3.2.5.3 Demand Forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast load increases

TLC forecasting data has become more detailed in recent times. The impact of distributed generation and demand side management has been considered in more detail since the 2010/11 review.

TLC now has load flow models for the entire network set up for each year in the planning period. Initial data are also available from the effects of demand billing and the upgrades that will be required if demand side strategies are effective listed down to zone substation transformer level.

A future work stream is to:

- Review models as further effects of demand side management become available.
- Put together detailed cost benefit models outlining the financial impact of demand side management strategies.

Investments by distributed generators during 2013/14 will also see the need for the model to be extended to include power electronic type wind turbines. Refinements are also planned for improved modelling of single phase lines.

TLC believes that the quality of work it has done in this area aligns with advanced industry best practice.

8.3.2.5.4 Policies on Distributed Generation

TLC has distributed generation policies in place. These policies have been reviewed and tested by external legal and engineering organisations. Recent substantial reductions in the cost of photovoltaic cells may trigger the need for a review of standards associated with latest inverter technology. Power electronic based wind turbines may also cause the requirement to review the standard going forward. We believe the quality of present policies is consistent with legislative, regulatory and technical best industry practice.

8.3.2.5.5 Policies on non-network solutions

TLC has introduced changes that ensure non-network solutions for both customers and network development are considered throughout the asset management and planning processes. TLC and its customers have learnt a lot from the introduction of these innovative and advanced industry best practice strategies. The quality of these strategies is continually improving.

8.3.2.5.6 Identification of the network development programme and actions to be taken including associated expenditure predictions

TLC has put a large investment into detailing the future development programme in Section 5. Programmes assume the savings that distributed generation and demand side management will bring about. Models and initial data are now becoming available to demonstrate the savings this is bringing about. The quality of future Plans will be improved by continually developing this research and analysis. TLC has used external parties to provide advice on these strategies.

Additional work is planned to verify the identification of development and renewal work during the coming planning period, this will also include external advice.

The details included in this section drive TLC's comprehensive pricing models. The quality of these will be continually enhanced as data improve. TLC pricing models in the medium future will be able to give accurate costs and margins of supplying customers connected to individual distribution transformers throughout the network.

8.3.2.6 Lifecycle Asset Management Planning (Maintenance and Renewal)

8.3.2.6.1 Maintain planning criteria and assumptions

TLC has maintenance planning criteria and assumptions and believes the quality is satisfactory given the best information that is currently available. Recent staff changes have slowed the development of financial and asset data developed in this area. Further work including closer links between specific individual maintenance tasks, the SMS system, the financial system and the data systems are planned. The basic framework for many of these improvements has been set up.

8.3.2.6.2 Routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category; including associated expenditure projections

TLC has in place practically focused inspection and maintenance policies and programmes. These are being followed and actions being taken are in compliance with this Plan. The difficulties experienced with the accounting system have made accurate tracking of expenditure difficult in recent times; however, on-going improvements are being made. Quality will also be further improved by building more detailed cost models of planned maintenance activities.

This initiative will improve the overall quality of the asset management and planning process associated with routine and preventative maintenance.

8.3.2.6.3 Asset Renewal and Refurbishment Policies

The asset renewal and refurbishment policies are detailed to what is considered a good level of quality. These policies will undergo a detailed review as part of future Plan preparation to ensure they continue to be relevant.

TLC has put considerable thought into these policies over the last eight years and this has aligned them with customer performance expectations. The organisational intellectual understanding of the policies is continuing to develop and improve. This is closely integrated with improving hazard control, (SMS and other systems), and development of the asset database.

8.3.2.6.4 Renewal or Refurbishment Programmes or Actions to be taken for each asset category including associated expenditure productions

TLC has put significant effort into data collection and using these in renewal and refurbishment programmes to produce high quality expenditure predictions. The 2012/13 review again worked through each project, checked its priority and ensured it was correctly linked and described in this plan and future expenditure predictions.

The quality of the programmes will be further enhanced as they are adjusted as a result of improved asset performance information coming from the recently installed data systems. Forward expenditure predictions will also be enhanced by better quality data coming from the financial systems. Detailed cost proposal renewal programmes are available out until 2026/27. It is believed this level of planning and detail aligns with industry best practice.

8.3.2.7 Risk Management

8.3.2.7.1 Methods, Details and Conclusions of Risk Policies

TLC has developed the quality of the Methods, Details and Conclusions of Risk Policies section as part of the 2010 review to improve quality. Quality will be further enhanced as better performance data become available from the new asset systems and further information becomes available from the impact of TLC's demand management strategies.

As part of the 2010/11 review, the risk section was expanded and a number of concepts from the asset management standard PAS55 – 1:2008 included. This included a section estimating the cost of risks associated with not doing particular functions. Quality of the risk section will be further enhanced when the work discussed in the forecasting section is further advanced. For example, it is hoped the risks associated with focusing on renewal, and delaying network reinforcement through demand management strategies will be better understood. In future Plans we need to ensure that the need for renewals is not resulting in loss of focus on development and that TLC will not end up with a capacity crisis. It is believed that the development of this section ensures it aligns with best industry practice.

8.3.2.7.2 Emergency response and contingency plans

TLC believes the overall quality of the asset management and planning contingency plans is adequate. It is recognised that if resources were available further work could be done in this area. Recent staff changes have caused disruption to plans in this area.

8.3.2.8 Evaluation of Performance

8.3.2.8.1 Progress against plan; both physical and financial

The review of the 2010 plan has included an extensive review of performance criteria and systems were developed during 2010 to give improved consistent reporting on these. It is considered that this review has significantly improved the quality of the asset management and planning focus.

The difficulties encountered with the change in accounting systems have attenuated the quality of some of the financial information. Work underway will reverse this with improved financial information becoming available for 2013 and future years from the new system.

8.3.2.8.2 Evaluation and comparison of actual performance against targeted performance objectives

The review of the 2010 plan included an extensive review of performance criteria and systems were developed during 2010 to give improved, consistent reporting on these. It is considered that this review has significantly improved the quality of the asset management and planning focus. The 2011 and 2012 reviews included work on the development of accurate data input and measurement of these indices.

8.3.2.8.3 Gap analysis and identification of important initiatives

This section completes this review. It is believed that this review has contributed overall quality of the asset management and planning process.

8.3.2.9 Expenditure Forecasts and Reconciliation

8.3.2.9.1 Forecasts of capital and operating expenditure for the minimum ten year asset management planning period

The capital and maintenance forecasts extend out until 2027 and the models that feed into the expenditure predictions are extensive. Significant improvements were made to these systems as part of the 2012 review with the transfer of this data to the Basix system. Many of the multiple spread sheet errors have been eliminated.

Systems to reconcile the financial information to the actual activity detailed in the asset system have been further developed and enhanced.

8.3.2.9.2 Reconciliations of actual expenditure against forecasts for the most recent financial year

The process is of good quality. The data available from the accounting system for the reconciliation is of improving quality. Reconciliations are done to the best accuracy possible. Looking forward, better accounting information is becoming available as systems are developed.

8.3.2.10 Further Disclosed Information

8.3.2.10.1 All significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers and qualified where possible

Key significant assumptions are stated and explained. Improvements to this section will come with continuous development and a better understanding of the Commerce Commission's and stakeholders' requirements for this section.

8.3.2.10.2 The basis on which significant assumptions have been prepared, including principal sources of information from which they have been derived

These have been stated. Improvements to this section will come with continuous development and a better understanding of the Commerce Commissions and stakeholder's requirements for this section.

8.3.2.10.3 The assumptions made in relation to these sources of uncertainty and the potential effects of the uncertainty on the prospective information.

These have been stated. As above, improvements to this section will come with continuous development and a better understanding of the Commerce Commission's and stakeholders' requirements for this section.

Section 9

9. Expenditure Forecasts and Reconciliations

9.1 Forecast of Capital and Operating Expenditure for the Planning Period (15 years)

Table 9-1 (A & B) and Table 9-2 (A & B) list the forward expenditure projections based on this plan.

The projects that have been included in the earlier years Plans have been included at the original value inflated by 3%. The actual value included in future projections has been reviewed before being re-inserted in forward projections. The new projects have been included in current dollar values and inflated at 3% to the actual year when works are proposed.

The predicted costs for 2012/13 are based on extensive analysis of needs as discussed in Section 5 and 6 of this plan. The totals are derived from the list of individual capital jobs and detailed maintenance activities.

The actual Capital Expenditure on Asset Management is the amount spent on assets commissioned in the 2010/11 financial year.

Fifteen Yearly Forecasts of Expenditure	Actuals for Most Recent Financial Year	Previous Forecast for Current Financial Year	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 1 to 7 (2012/13 to 2018/19)						
	Year -1	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
CAPITAL EXPENDITURE	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Customer Connections	1,876,819	3,229,050	584,609	1,935,930	643,397	1,854,907	932,299	1,363,444	1,334,099
System Growth	78,010	448,050	1,074,436	1,056,137	116,838	337,613	713,886	1,102,817	609,064
Reliability, Safety & Environment	939,100	1,339,000	1,415,329	2,216,950	1,475,801	2,476,259	1,034,863	1,323,679	1,006,339
Asset Replacement & Renewal	4,381,917	6,078,652	6,460,661	7,573,509	7,332,050	7,547,969	7,437,085	8,369,997	8,556,640
Asset Relocations	54,319	51,500	52,168	53,733	55,345	57,005	58,715	60,477	62,291
Subtotal - Capital Expenditure on Asset Management	**7,330,165**	**11,146,252**	**9,587,202**	**12,836,259**	**9,623,430**	**12,273,753**	**10,176,849**	**12,220,414**	**11,568,433**
OPERATIONAL EXPENDITURE									
Routine & Preventive Maintenance	940,259	1,650,027	1,676,874	1,727,180	1,778,996	1,832,366	1,887,337	1,943,957	2,002,276
Refurbishment & Renewal Maintenance	233,533	534,896	614,676	633,117	652,110	671,673	691,824	712,578	733,956
Fault & Emergency Maintenance	1,169,419	1,399,648	1,503,792	1,548,906	1,595,373	1,643,234	1,692,531	1,743,307	1,795,606
Subtotal - Operational Expenditure on Asset Management	**2,343,211**	**3,584,571**	**3,795,342**	**3,909,203**	**4,026,479**	**4,147,273**	**4,271,691**	**4,399,842**	**4,531,837**
TOTAL DIRECT EXPENDITURE on Distribution Network	**9,673,376**	**14,730,823**	**13,382,544**	**16,745,462**	**13,649,909**	**16,421,026**	**14,448,540**	**16,620,256**	**16,100,270**
Overhead to Underground Conversion Expenditure	-	-	-	-	-	-	-	-	-

TABLE 9-1A: FORWARD EXPENDITURE PREDICTIONS 2012/13 TO 2018/19 (WITH INFLATION) WITH 2010/11 ACTUALS

Fifteen Yearly Forecasts of Expenditure	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 8 to 15 (2019/20 TO 2026/27)							
	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
CAPITAL EXPENDITURE	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Customer Connections	1,676,503	1,287,337	1,855,364	1,365,736	1,406,708	1,862,121	1,492,376	1,537,148
System Growth	1,810,716	1,784,037	1,315,953	2,134,414	858,517	1,123,937	2,000,359	3,351,852
Reliability, Safety & Environment	1,471,386	1,422,029	1,307,698	740,038	1,583,049	1,756,422	953,363	841,681
Asset Replacement & Renewal	9,597,322	8,926,551	9,317,002	8,597,397	7,792,529	9,809,008	8,431,948	9,214,439
Asset Relocations	64,160	66,084	68,067	70,109	72,212	74,379	76,610	78,908
Subtotal - Capital Expenditure on Asset Management	**14,620,087**	**13,486,038**	**13,864,084**	**12,907,693**	**11,713,015**	**14,625,867**	**12,954,657**	**15,024,028**
OPERATIONAL EXPENDITURE								
Routine & Preventive Maintenance	2,062,344	2,124,214	2,187,940	2,253,579	2,321,186	2,390,822	2,462,546	2,536,423
Refurbishment & Renewal Maintenance	755,974	778,654	802,013	826,073	850,856	876,381	902,673	929,753
Fault & Emergency Maintenance	1,849,474	1,904,958	1,962,107	2,020,970	2,081,599	2,144,047	2,208,369	2,274,620
Subtotal - Operational Expenditure on Asset Management	**4,667,792**	**4,807,826**	**4,952,061**	**5,100,622**	**5,253,641**	**5,411,250**	**5,573,588**	**5,740,795**
TOTAL DIRECT EXPENDITURE on Distribution Network	**19,287,879**	**18,293,863**	**18,816,145**	**18,008,315**	**16,966,656**	**20,037,117**	**18,528,244**	**20,764,823**
Overhead to Underground Conversion Expenditure	-	-	-	-	-	-	-	-

TABLE 9-1B: FORWARD EXPENDITURE PREDICTIONS 2019/20 TO 2026/27 (WITH INFLATION)

Table 9-2A and 9-2B show the same forward expenditure projections without inflation

Fifteen Yearly Forecasts of Expenditure	**FORECAST EXPENDITURE PREDICTIONS FOR YEARS 1 to 7 (2012/13 to 2018/19)**						
	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**
CAPITAL EXPENDITURE	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Customer Connections	567,582	1,824,800	588,800	1,648,061	804,210	1,141,863	1,084,745
System Growth	1,043,142	995,510	106,923	299,965	615,804	923,592	495,225
Asset Replacement & Renewal	6,272,486	7,147,788	6,727,659	6,732,577	6,422,711	7,014,698	6,959,894
Reliability, Safety & Environment	1,374,105	2,092,193	1,360,863	2,205,596	895,079	1,109,447	818,245
Asset Relocations	50,648	50,648	50,648	50,648	50,648	50,648	50,648
Subtotal - Capital Expenditure on Asset Management	**9,307,963**	**12,110,939**	**8,834,893**	**10,936,847**	**8,788,452**	**10,240,248**	**9,408,757**
OPERATIONAL EXPENDITURE							
Routine & Preventive Maintenance	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033
Refurbishment & Renewal Maintenance	596,773	596,773	596,773	596,773	596,773	596,773	596,773
Fault & Emergency Maintenance	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992
Subtotal - Operational Expenditure on Asset Management	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**
TOTAL DIRECT EXPENDITURE on Distribution Network	**12,992,762**	**15,795,737**	**12,519,691**	**14,621,645**	**12,473,251**	**13,925,046**	**13,093,556**
Overhead to Underground Conversion Expenditure	-	-	-	-	-	-	-

TABLE 9-2A: FORWARD EXPENDITURE PREDICTIONS 2012/13 TO 2018/19 (WITHOUT INFLATION)

Fifteen Yearly Forecasts of Expenditure	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 8 to 15 (2019/20 TO 2026/27)							
	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
CAPITAL EXPENDITURE	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Customer Connections	1,323,447	986,637	1,380,566	986,637	986,637	1,268,014	986,637	986,637
System Growth	1,429,396	1,367,316	979,193	1,541,947	602,147	765,347	1,322,474	2,151,427
Asset Replacement & Renewal	7,576,215	6,841,459	6,932,726	6,210,946	5,465,526	6,679,460	5,574,513	5,914,399
Reliability, Safety & Environment	1,161,526	1,089,867	973,050	534,619	1,110,319	1,267,857	630,286	540,243
Asset Relocations	50,648	50,648	50,648	50,648	50,648	50,648	50,648	50,648
Subtotal - Capital Expenditure on Asset Management	**11,541,232**	**10,335,926**	**10,316,184**	**9,324,798**	**8,215,278**	**10,031,327**	**8,564,558**	**9,643,354**
OPERATIONAL EXPENDITURE								
Routine & Preventive Maintenance	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033	1,628,033
Refurbishment & Renewal Maintenance	596,773	596,773	596,773	596,773	596,773	596,773	596,773	596,773
Fault & Emergency Maintenance	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992	1,459,992
Subtotal - Operational Expenditure on Asset Management	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**	**3,684,798**
TOTAL DIRECT EXPENDITURE on Distribution Network	**15,226,031**	**14,020,725**	**14,000,982**	**13,009,596**	**11,900,076**	**13,716,125**	**12,249,356**	**13,328,153**
Overhead to Underground Conversion Expenditure	-	-	-	-	-	-	-	-

TABLE 9-2B: FORWARD EXPENDITURE PREDICTIONS 2019/20 TO 2026/27 (WITHOUT INFLATION)

As outlined in earlier sections:

- Customer Connection costs: Dependent on economic activity and will fluctuate. The decrease in expenditure for 2012/13 is a reflection on the current economy.
- System Growth: As above, but also dependent on where the activity takes place. The system growth project for 2012/13 is the Ohakune upgrade. Other significant expenditure is on voltage regulators; there are 3 projects included in the 2012/13 plan.
- Asset Replacement and Renewal: Mostly based on lines inspections that apply the criteria as outlined in earlier sections. TLC owns almost 5000km of lines that require on-going renewal.
- Reliability, Safety and Environment: The TLC network has equipment that, by its nature, has hazards that require renewal to eliminate/minimise. The network, because of its rural nature, has reliability issues and there are environmental constraints with equipment that do not comply with present day expectations. Expenditure for addressing these is included in the plan and outlined in detail in Sections 5.
- Asset Relocations: Asset relocations, such as the need to move equipment for road works, are driven by other parties.
- Routine and Preventative Maintenance: Is driven by the various maintenance programmes and equipment age and condition. TLC's equipment is old by industry standards.
- Refurbishment and Renewal Maintenance: TLC capitalises most of its renewal and replacement. Expenditure of this nature is mostly associated with direct technical activities associated with the renewal programme. For example, some costs associated with design, landowner liaison, legal costs, job package preparation, audits and as built records/data recording.
- Fault and Emergency Maintenance: The weather is the biggest factor in fault and emergency maintenance. Storms that involve wind speeds greater than 75km/hr typically have an impact on the TLC network.

9.2 Overhead to Underground Conversions

There are no overhead to underground conversions included in forward estimates.

Short lengths of cable are used to get into and out of substations and are included in Section 5 and 6. Similarly, short lengths of cable are included in a number of the hazard elimination/minimisation projects, typically to tidy busy, confusing poles with multiple circuits, non standard installations and potential traps for staff. In most cases the poles are left, but the number of circuits or terminations on them is reduced by bypassing one or two circuits with cable. In these cases the overhead line remains and is assumed to not be a conversion.

Similarly, estimates do contain two safety projects where overhead conductors will be removed, raised or insulated where lines cross world renowned fishing spots on the Tongariro and one other river on the edge of Lake Taupo. Presently the lines are draped with fishing lines. A cable is an option to bypass the crossing for one of these projects. The pole count is not likely to change and the present river crossing strain poles will become cable termination poles. Cables will be mounted on the adjacent bridge. These cases have not been assumed to be conversions.

Renewal estimates also include low voltage reticulation renewal. In most cases poles will be left; however, there will be a minority of sites where this is not practical and small sections of cable will be installed to get around tight intersections and other obstacles such as specimen trees and the like.

9.3 Forecast of Capital and Operating Expenditure Actual Versus Estimate Comparison

Table 9-3 lists the variations between actual and forecast expenditure for 2010/11 in disclosure format.

Variance between Actual Expenditure and Previous Year Forecasts	Actuals for Most Recent Financial Year	Previous Forecast for Most Recent Financial Year	% Variance
	Year -1	Year -1	
	2010/11	2010/11	
CAPITAL EXPENDITURE	**(a)**	**(b)**	**(a)/(b)-1**
Customer Connections	1,876,819	1,030,000	82% (U)
System Growth	78,010	130,000	-40% (F)
Asset Replacement & Renewal	4,381,917	5,756,101	-24% (F)
Reliability, Safety & Environment	939,100	805,000	17% (U)
Asset Relocations	54,319	50,000	9% (U)
Subtotal - Capital Expenditure on Asset Management	**7,330,165**	**7,771,101**	**-6%** (F)
OPERATIONAL EXPENDITURE			
Routine & Preventive Maintenance	940,259	1,216,806	-23% (F)
Refurbishment & Renewal Maintenance	233,533	280,052	-17% (F)
Fault & Emergency Maintenance	1,169,419	1,198,302	-2% (F)
Subtotal - Operational Expenditure on Asset Management	**2,343,211**	**2,695,160**	**-13%** (F)
TOTAL DIRECT EXPENDITURE on Distribution Network	**9,673,376**	**10,466,261**	**-8%** (F)

TABLE 9-3: VARIATIONS BETWEEN ACTUAL AND FORECAST EXPENDITURE

Note: When analysis work was completed in preparation of this document, variances were found between the categories in the 2010/11 disclosure of actual 2010/11 spends, and those in Table 9-3. The total for Capital Expenditure on Asset Management is the amount spent on assets commissioned in the 2010/11 financial year.
The Operational Expenditure figures differ from the totals shown in section 8.1.3 due to differences in defining direct maintenance expenditure between TLC's planning format and disclosure format. The reason for this was confusion over the definitions for expenditure included in the 2008 disclosure requirements.

9.4 Reconciliation of Actual Expenditure against Forecast for the Most Recent Financial Year for which Data is Available

Full detail on a project by project basis under asset type categories is included in earlier sections. Reformatting and summarising this information into the disclosure categories is outlined in the following sections.

9.4.1 Capital Expenditure: Customer Connection

CUSTOMER CONNECTION EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Domestic and small commercial new/upgrade connection. TLC contributions (earthings, transformers and brought forward renewals).	511,443	535,000	-4% (F)
Unallocated contingencies for new customer connections – industrial, subdivisions and other.	1,365,376	* 495,000	176% (U)
Total	**1,876,819**	**1,030,000**	**82%** (U)
** This figure was inaccurately presented in the 2010 AMP Section 5 data due to errors in interpreting data across a large number of linked spreadsheets. The level of inaccuracy was relatively minor.*			

TABLE 9-4: REASONS FOR VARIANCE ACTUAL TO ESTIMATES; CUSTOMER CONNECTION

Table 9-4 lists the summary expenditure components that aggregated into customer connection expenditure. Domestic and small commercial new/upgrade expenditure trailed slightly lower than estimates. Industrial connection expenditure tracked higher than estimates due to two significant projects.

These were:

1. The Mokai Energy Plant
2. The Te Anga substation and other dedicated assets associated with the connections of the Speedys Road distributed generation hydro scheme (as described in section 8 of this document) resulted in the estimates being exceeded.

9.4.2 Capital Expenditure: System Growth

SYSTEM GROWTH EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Install regulators to supplement 11kV network.	78,010	* 130,000	-40% (F)
Total	**78,010**	**130,000**	**-40%** (F)
** This figure was presented as 85,000 in the 2010 AMP Section 5 data due to errors in interpreting data across a large number of linked spreadsheets.*			

TABLE 9-5: REASONS FOR VARIANCE ACTUAL TO ESTIMATES: SYSTEM GROWTH

Table 9-5 shows the system growth expenditure variance. The project was commissioned by year end; however, contractor invoices had not been all received. The remaining costs will flow into the 2011/12 financial year.

9.4.3 Capital Expenditure: Asset Replacement and Renewal

ASSET REPLACEMENT AND RENEWAL EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Lines and equipment.	4,381,917	5,756,101	-24% (F)
Total	**4,381,917**	**5,756,101**	**-24%** (F)

TABLE 9-6: VARIANCE: ACTUAL TO ESTIMATE – ASSET REPLACEMENT AND RENEWAL

Table 9-6 shows that asset replacement and renewal expenditure tracked under the estimated amount. Most projects were completed for slightly less than estimates. Due to a lack of technical resources, a number were not fully completed and the costs flowed into the 2011/12 financial year. Further details on a project by project basis are included in section 8.

9.4.4 Capital Expenditure: Reliability, Safety and Environment

Table 9-7 summarises the components that caused the variance and the reasons.

RELIABLILITY, SAFETY AND ENVIRONMENT EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Reliability and security.	170,294	* 184,,418	-8% (F)
Hazardous equipment renewals	678,283	* 521,055	30% (U)
Environmental	90,523	* 99,527	-9% (F)
Total	**939,100**	*** 805,000**	**17%** (U)
** These figures vary from those presented in the 2010 AMP Section 5 data. Slight errors occurred due to the large number of linked spreadsheets.*			

TABLE 9-7: REASONS FOR VARIANCE ACTUAL TO ESTIMATES: RELIABILITY, SAFETY AND ENVIRONMENT

Table 9-7 summarises the variances of the categories that make up the reliability, safety and environmental expenditure category. The overall variance of 17% was caused by a variance of 30% in the hazardous equipment renewals expenditure.

The two significant reasons for this were:

1. A number of projects were more complex than expected when detailed designs were completed.
2. A number of carry-overs coming forward from the previous financial year.

9.4.5 Capital Expenditure: Asset Relocation

ASSET RELOCATION EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Asset relocation.	54,319	50,000	9% (U)
Total	**54,319**	**50,000**	**9%** (U)

TABLE 9-8: REASONS FOR VARIANCE ACTUAL TO ESTIMATES: ASSET RELOCATION

Examination of Table 9-8 shows that asset relocation expenditure tracked within the 10% tolerance level. Expenditure includes some easement costs.

9.4.6 Operational Expenditure: Routine and Preventative Maintenance

ROUTINE AND PREVENTIVE MAINTENANCE EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Routine and preventative maintenance	940,259	1,216,806	-23% (F)
Total	**940,259**	**1,216,806**	**-23%** (F)

TABLE 9-9: VARIANCE: ACTUAL TO ESTIMATE – ROUTINE AND PREVENTATIVE MAINTENANCE

Table 9-9 shows that this expenditure tracked under estimate and outside the 10% tolerance level. Less abnormal events requiring follow up maintenance was the primary reason for this.

9.4.7 Operational Expenditure: Refurbishment and Renewal Maintenance

REFURBISHMENT AND RENEWAL MAINTENANCE EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Refurbishment and renewals	233,533	280,052	-17 (F)
Total	**233,533**	**280,052**	**-17** (F)

TABLE 9-10: REASONS FOR VARIANCE ACTUAL TO ESTIMATES: REFURBISHMENT AND RENEWAL MAINTENANCE

Table 9-10 shows that the refurbishment and renewal maintenance expenditure tracked below the estimated amount. This followed the lower than expected level of capital refurbishment and renewal expenditure. Projects were completed for lesser amounts than anticipated and a number of projects were rolled forward due to a lack of available technical resources.

9.4.8 Operational Expenditure: Fault and Emergency Maintenance

FAULT AND EMERGENCY MAINTENANCE EXPENDITURE 2010/11			
Description	**Actual**	**Estimate**	**% Variance**
Fault and emergency maintenance	1,169,419	1,198,302	-2% (F)
Total	**1,169,419**	**1,198,302**	**-2%** (F)

TABLE 9-11: REASONS FOR VARIANCE ACTUAL TO ESTIMATES: FAULTS AND EMERGENCY REPAIRS

Table 9-11 shows that fault and emergency maintenance expenditure tracked comfortably within the 10% tolerance level.

Section 10

10. Further Disclosed Information

10.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

10.1.1 Growth funding

It has been assumed the cost of developing the network for growth and customer connections, other than a few "catch up projects," will be financed by the additional income from the increased customer demand.

10.1.2 Continuance of supply

The 2010 Electricity Act has been amended in a way that requires TLC to continue to operate uneconomic lines.

10.1.3 Distributed Generation

It is taken distributed generation connections will continue to be developed and that the regulators will resolve rules on complex issues associated with the likes of grid exit power factor. It is assumed that industry rules will be formatted in such a way that grid connected and distribution connected generation face a similar matrix of costs. (This is currently not the case.) It is also assumed that existing load taking customers will not be penalised in a way that cross subsidises the connection of generation.

10.1.4 Demand side management and peak control

That the industry will increasingly recognise the importance of demand side management and peak control. A consequence of these will be recognition and support for TLC's demand based charging system by regulators.

10.1.5 Economic activity

It has been assumed that economic activity based on primary production and processing will continue to develop. The Asset Management Plan assumes land use development in a gradual, slow way. That is, the forward assumptions include allowances for existing dairying land being converted back to dry stock farming and vice versa. It is assumed that when land is converted to dairying, present day technologies will be incorporated into new milking sheds. These tend to be bigger and more automated than older installations. (The electrical equipment involved can also introduce harmonics and cause power factor attenuation). The forward land use assumption does not include large scale development of irrigation.

10.1.6 Reliability and quality

It has been assumed that customers will want reliability and quality standards equivalent to or better than present to support lifestyle tools such as electronic appliances, computers and media devices. (These will be subject to customer consultation in compliance with Commerce Commission Customised Price Path requirements).

10.1.7 Hazards

It has been assumed that stakeholders want a network that does not cause an unacceptable level of hazard to the general public, staff, or animals. Plans are in place to reduce network hazards over the planning period. It is assumed that there will be no stepped inputs to significantly alter this plan. The Asset Management Plan includes specific sites and conceptual design detail.

10.1.8 Pricing

It has been assumed that TLC will continue with its present pricing structures that are designed to be transparent, promote demand side management, encourage distributed generation and reflect asset values/costs.

10.1.9 Inflation

It has been assumed that inflation will continue though the planning period.

10.1.10 Performance Measures

It has been assumed that stakeholders want development of performance measures that align with customer expectations.

10.1.11 Customers Ability to Pay

It has been assumed that customers in the King Country are not affluent and have limited ability to pay increasing line and energy charges.

10.2 A Description of Changes Proposed where the Information is Not Based on the Distribution Business's Existing Businesses

The information is based on the distribution business's existing businesses.

10.3 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

10.3.1 Growth funding

The principle that growth funding will come from increased income is based on having charges and pricing structure in place that create income to fund investment in new connections and system growth from this development. The investment needs to produce returns that are bankable.

The principal sources of information for developing this assumption are:

- Network models that calculate network capacity and the impacts of growth on the connection chain.
- The cost of the necessary network development.
- Bankable investment criteria.

10.3.2 Continuance of supply basis

The principal source of information for developing this assumption is the contents of the Act.

10.3.3 Distributed Generation

This assumption is based on government policy statements and the lack of rules to cover some of the complex technical issues associated with connecting distributed generation.

It has also been assumed that the regulators will want to make the connection of generations equitable between transmission and distribution networks.

The principal sources of information for developing these assumptions are:

- Government policy statements.
- Electricity Governance Rules
- Transmission connection charges.
- Various papers produced by officials.
- Network studies showing the effects of distributed generation.

10.3.4 Demand side management, peak control and power factor

This assumption is based on the fact that power systems have to be designed for peak capacity.

Increased power system efficiency and minimisation of investment comes largely by minimising demand. Power factor is also directly related to power system efficiency and is part of demand side management. Losses and investment are minimised if power factors are close to unity and demands are controlled.

This assumption is based on the information that suggests investors will want to minimise costs for network development, i.e. customer connection and growth development costs.

All stakeholders want costs controlled and environmental lobbies want losses minimised. Power factor and changing demand behaviour affects losses.

The initial results of data analysis are indicating that TLC's demand side management signalling through financial signalling is effective. The forecasts in the Asset Management Plan assume this effect continues. Section 5 of the Plan includes some initial forecasting work on the effects if TLC did not adapt this strategy. This work suggests that without demand side management many more network components would be beyond their capacity limits by the end of the planning period. Indications are that the benefits of demand side management have the potential to be significant.

10.3.5 Economic activity

The network studies have assumed continued development of the area. Different rates have been used on the land types and present usage. For example, it has been assumed flat or rolling land will see greater development than extreme hill country in remote locations. Areas to which people are currently attracted to build new homes and invest in related enterprises have been given greater growth rates than locations that are less popular and more remote.

Overall, an average growth rate of less than peak "boom" times, but reflective of average consistent growth, has been used as a base. TLC's growth is also influenced by rural based industrial enterprises. Models have assumed that most of these industries will continue with a gradual increase in load as various machines within the plant are renewed. It has also been assumed that, because of TLC's pricing structures, industrial customers will focus on demand side management by way of power factor correction and recognising the demand the various processing within the plant creates.

The principal sources of information for developing these assumptions are:

- CPI.
- Land information.
- Subdivision development: sizes and numbers.
- Distribution capacity and numbers.
- New connection numbers.
- New housing areas.
- Areas that are static, or depopulating.
- Industrial customer feedback and comment.
- Previous energy and demand growth figures.
- Primary produce pricing and trends in these.
- Predictions on primary produce long term forecasts.
- Predictions on the leisure markets.

10.3.6 Reliability and quality

The reliability and quality assumption is based on the understanding that customers want a continual improvement in reliability and quality. Specifically, this assumption is based on the number of complaints that occur when the power goes off and/or appliances will not go or are destroyed.

The principal sources of information for developing these assumptions are via:

- Customer feedback.
- Complaints.
- Focus groups.
- Customer surveys.
- Customer representatives.
- Other community input.

10.3.7 Hazards

The hazard assumption is based on people not wanting to get shocked or electrocuted and, if they do, the legal and emotional liabilities that stakeholders will face if this is caused by lack of renewal programmes, maintenance, and general failure to operate a network with acceptable levels of hazards. It is also assumed that the organisation complies with Electrical (Safety) Regulations. The assumption is also based on the liabilities associated with not taking all practicable steps to eliminate, isolate or minimise hazards.

10.3.8 Pricing structures

The assumption is based on the regulators and stakeholders continuing to encourage efficient network development and for revenue to reflect cost drivers.

10.3.9 Inflation

The rate of inflation for cost increases has been based on recent CPI figures. The assumption is based on published CPI data.

10.3.10 Considerations associated with adverse events

If some sort of plan is not followed for maintenance, renewal and development, then the chance of adverse events substantially increases. The principal sources of information from which they have been derived include:

- Legislation.
- Engineering industry experience.
- Industry papers and event information.
- PAS55 asset management standard.

10.3.11 Performance

It is considered important that performance measures are in place to quantify performance in a way that aligns with stakeholders' expectations.

The principal sources of information from which they are derived include:

- Terms and Conditions of Supply.
- Customer surveys.
- Customer complaints and feedback.
- Commerce Commission performance measures.
- Measures that have been aligned and developed over time with the objective of making information more understandable to customers.

10.3.12 Customers ability to pay

The principal source of information suggesting customers have limited ability to pay includes things such as:

- School decile ratings.
- Government "wealth information" associated with electorates.
- Customers and stakeholders feedback.

10.4 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

10.4.1 Growth funding

If growth as assumed does not go ahead, then other than a few catch-up projects, the expenditure for customer connections and growth as detailed in the long term plan would reduce. Similarly, if growth increase is greater than estimates, expenditure will be greater.

Load growth estimates, and actuals, over recent years are detailed in the Asset Management Plan. Overall, a conservative approach has been taken to growth. The most likely variation will be greater growth in some parts of the network driven by specific commercial activity, e.g. milk processing.

10.4.2 Continuance of supply

The 2010 amendment of the Electricity Act has meant that the effect on the organisation of the renewal programmes will be as described in this Plan. Hence there will be no external money to subsidise rural lines and, as such, the programmes have to be funded from TLC's income.

The present pricing structures means there is an element of cross-subsidisation between urban and rural customers, (approximately 30%); if this were to be removed remote customers would see an increase of about 100% in there charges.

10.4.3 Distributed Generation

If regulators enforce grid exit power factor requirements and costs are passed on to generation, the economics of some existing and new distributed generation sites will become marginal. If the costs are passed on to load taking customers, charges will have to increase.

If regulators accept that grid exit power factors with generation connected will be lower, but the same amount of reactive power would have to be supplied into that point with or without the active power injection, then there would be no additional revenue requirements (status quo).

The costs associated with a greater uptake of distributed generation will mean that the customer connection and system growth expenditure will increase to accommodate this.

10.4.4 Demand side management and peak control

If TLC were not signalling network constraints, then the demand would likely grow faster than if it was signalled. The figures used in the long term estimates are about .25% to .75% less than the average demand growth if it were not implemented.

This assumption is based on the initial data available. If a greater demand growth reduction occurs then system growth needs will be less. If customers do not react, the growth in demand will cause a higher level of expenditure. Initial analysis work completed at the time of writing indicates that a growth greater than forecast will cause significant system strengthening expenditure to be triggered. (See Section 5 of AMP for further details on this work.)

Customers' reaction to demand side management signals to date has been encouraging. Retailers have yet to introduce energy rates that provide reasonable incentives for customers to manage their demands further.

Because demand billing is unique and new to many customers (even though it was extensively used down to relatively small commercial customers up until the Bradford reforms in the early 1990s, the concept has generally been ignored industry wide since this time), most have trouble understanding the concept and TLC has incurred criticism from some.

If retailers introduce incentives and the industry moves to implement more demand side management schemes, then customers will likely understand the issue better and greater savings will occur. The national roll out of advanced meters will make it easier for more parties to adopt this approach.

10.4.5 Economic activity

If economic activity increases, growth related capital expenditure will increase. If economic activity reduces, the reverse will take place.

If economic activity declines to a level that sees a number of the rural processors leave the area, then TLC will have to either reduce renewals or increase revenue from the remaining customers. Reducing renewals will involve stakeholders accepting that they will be operating and accepting liabilities associated with a network that contains hazards that should be eliminated or minimised.

10.4.6 Reliability and quality

The forward plans include projects totalling about $200,000 to $500,000 p.a. for reliability development (mostly automated switches). If stakeholders do not want a gradual improvement in reliability, then this expenditure could be eliminated.

10.4.7 Hazards

If stakeholders decide not to have a programme with projects that eliminate/minimise hazards, then the forward development expenditure would reduce by approximately $1million p.a.

The present programme eliminates or minimises the worst of the hazards by about 2020. The annual spend would be reduced in the medium term if the programme were lengthened.

10.4.8 Pricing structures

The present pricing structure promotes demand side management and protects revenue against movements in energy flow triggered by shortages or greater uptakes of small generation behind meters. The present pricing structures also encourage demand side responses such as power factor correction.

A change in the structure would increase the risks to revenue in the future during energy shortages or greater uptake of solar panels etc.

10.4.9 Inflation

Forward estimates are based on an inflation rate of 2 to3%. Higher inflation will mean higher costs in dollar terms. Lower inflation will give the reverse. (The inflation referred to is that associated with the renewal and construction of distribution networks, not general inflation.)

10.4.10 Likelihood consequence control

This plan details the various policies and strategies that are in place to control the impact of adverse events. Adverse events have a high level of uncertainty. i.e. earthquakes, storms, floods, volcanic eruptions etc. Any of these events has a level of likelihood that flows through into this Plan and other disclosed information. The other variables include economic prosperity in the rural and tourism areas and the future regulatory climate.

10.4.11 Performance

The performance measures are currently aligned with customer simplification needs, the asset management system and Commerce Commission criteria.

Variation from these will lead to periods of uncertainty in terms of performance measurements. It will take time to set up systems to measure new indices.

10.4.12 Customers ability to pay

There is little uncertainty associated with the limited ability of TLC's customers to pay ever increasing charges. The potential effect of this uncertainty/certainty will be an increased pressure for TLC to carry out its renewal work at the lowest possible cost. This means that forward expenditure predictions may be greater than the actual cost of completing work.

Section 11

11. Stakeholder Requested Information

11.1 Background

The format of this plan follows that specified in the Commerce Commission requirements. TLC has followed this format as closely as possible to ensure compliance with the Commissions assessment, and the building of this information suitable for other related disclosure and mandatory reporting requirements.

TLC has had a number of stake holder requests for the works programme to be presented in a more understandable (concise), format. Section 11 has been added to fulfil these requests.

It needs to be recognised that the works programme consists of many integrated activities. Unbundling these into a simple format is a challenge. TLC also receives various other requests for specific information that often takes a relatively long time to prepare, and may be of interest to other stakeholders.

It is envisioned that Section 11 of the AMP will be developed to provide commonly requested information. Preparing and submitting it as part of the annual planning process will be a more efficient and effective use of time as opposed to one off requests.

11.2 Proposed Capital Works 2012/13 to 2026/27

The list in table 11-1 includes all capital work proposed out to 2026/27. All projects are subject to review until the work is actually commenced to ensure they are necessary and the timing is appropriate. The projects are listed by Year, Point of Supply (GXP), Category, Asset Group, a brief description and cost. The values are in current dollars, without inflation and inclusive of engineering costs.

PROPOSED CAPITAL WORKS: 2012/13				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	159k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	32k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	106k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	80k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	101k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k

PROPOSED CAPITAL WORKS: 2012/13				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	177k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	107k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Mokau	128-06 11kV Line Renewal	376k
Hangatiki	Line Renewal	Mokauiti	115-04 11kV Line Renewal	138k
Hangatiki	Line Renewal	Benneydale	103-05 11kV Line Renewal	257k
Hangatiki	Line Renewal	Benneydale	103-06 11kV Line Renewal	139k
Hangatiki	Line Renewal	Mokauiti	115-03 11kV Line Renewal	275k
Hangatiki	Line Renewal	Waitomo	108-03 11kV Line Renewal	104k
Hangatiki	Line Renewal	Aria	114-03 11kV Line Renewal	117k
Hangatiki	Line Renewal	McDonalds	110-05 11kV Line Renewal	248k
Hangatiki	Line Renewal	Maihiihi	111-08 11kV Line Renewal	88k
Hangatiki	Line Renewal	Hangatiki East	102-03 11kV Line Renewal	63k
Hangatiki	Line Renewal	Waitomo	108-03 LV Line Renewal	64k
Hangatiki	Line Renewal	Mokau	128-06 LV Line Renewal	42k
Hangatiki	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Replace 11 kV Circuit breaker with modern equipment and increase the functionality of the breaker. Risk to reliability and security and protection not operating	68k
Hangatiki	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Modify and install oil bunding, oil separation and earthquake restraints.	28k
Hangatiki	Substation and 33 kV Development	Te Waireka Zone Substation	ZSub203 Modify and install bunding, oil bunding, oil separation and earthquake restraints.	28k

PROPOSED CAPITAL WORKS: 2012/13				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Line Renewal	Raurimu	410-01 11kV Line Renewal	237k
National Park	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Transformer Refurbishment	90k
National Park	Switches	Raurimu Feeder	FED410 Install Recloser for Retaruke tap-off at Raurimu Hill.	56k
National Park	Switchgear	Chateau	T4066 Upgrade Transformer Install Xiria.	45k
Ohakune	Feeder Development	Turoa	415-04 Redesign over LV and HV configuration for Rangataua. Check loading of all transformers including 20M09. Work in association with planned change of two pole structures 20M07 in 12/13 year and 20M08 in 13/14. Assess LV wire size and extending LV. Work to alleviate low voltage problems and possible development of empty sections. Do part in 12/13 and part in year 16/17.	84k
Ohakune	Line Renewal	Turoa	415-03 11kV Line Renewal	71k
Ohakune	Substation and 33 kV Development	Ohakune Point of Supply	ZSub517 Take supply for part of area from neighbouring Transpowers Tangiwai Grid Exit.	464k
Ohakune	Switches	Tangiwai	5673 Automate switch	23k
Ohakune	Switches	Turoa	6356 Switch Automation. Install a Schnider Motor Drive unit & Aerial	23k
Ohakune	Switchgear	Ohakune Town	20L50 Upgrade transformer to include RTE	45k
Ohakune	Switchgear	Ohakune Town	6321 Install RMU to remove 3 cables from pole in Ayr Street and two cables fused off this switch. This will supply 20L61, 20L59 and 20L60.	45k
Ongarue	Line Renewal	Tuhua	422-02 11kV Line Renewal	130k
Ongarue	Line Renewal	Western	403-05 11kV Line Renewal	192k
Ongarue	Line Renewal	Ohura	413-05 11kV Line Renewal	230k
Ongarue	Line Renewal	Ongarue	421-01 11kV Line Renewal	214k
Ongarue	Transformers - 2 Pole Structures	Ongarue	T4128 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Look at new options as 04I01 may be overloaded.	30k
Ongarue	Transformers - 2 Pole Structures	Northern	01A50 Rebuild structure. 11 kV only 4m above ground. Ground mount transformer, if possible use a second hand 100 kVA.	48k
Ongarue	Transformers - 2 Pole Structures	Northern	06H11 Raise equipment on structure, recloser at only 3.75m above the ground.	48k

PROPOSED CAPITAL WORKS: 2012/13				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Transformers - 2 Pole Structures	Ongarue	04I01 This is a structure with two isolating SWER transformers. Split cost over 04I01 and T4128. Structure needs a total rebuild. Check loading on 04I01 as load flow program indicates transformer could be overloaded.	30k
Tokaanu	Line Renewal	Kuratau	406-01 11kV Line Renewal	18k
Tokaanu	Line Renewal	Waihaha	426-04 11kV Line Renewal	241k
Tokaanu	Line Renewal	Turangi	423-01 11kV Line Renewal	166k
Tokaanu	Line Renewal	Tokaanu / Kuratau 33	607-01 33kV Line Renewal	245k
Tokaanu	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 Rebuild fence	68k
Tokaanu	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 Add additional 33 kV switchgear. Leave existing reclosers. Upgrade protection schemes to ensure primary and backup protection is reliable. New 33 kV in year 12/13. Underground and remove double cct to be done at same time as far as 5673 tap-off. (See 11kV line renewals)	206k
Tokaanu	Substation and 33 kV Development	Tokaanu Point of Supply	ZSub515 Install switchgear capable of breaking a capacitive circuit. Sectos Switch in stock can be used for this project.	68k
Tokaanu	Switches	Turangi	5208 Install a 4 way Xiria at tap-off 5208 to supply Turangi and have a parallel with Rangipo Hautu	56k
Tokaanu	Switches	Turangi	6191 Automate 6191 tie to Hirangi Feeder from Turangi. This is an existing Magnefix therefore the switch will need to be changed.	56k
Tokaanu	Transformers - 2 Pole Structures	Oruatua	09U10 Replace with ground mounted transformer. Adjacent high wooden fence makes any structure a hazard.	68k
Tokaanu	Transformers - 2 Pole Structures	Oruatua	09U07 Replace with a ground mounted transformer. Pole requires replacing and LV through trees. Earth mat looks to be damaged.	68k
Tokaanu	Transformers - Ground Mounted	Turangi	10S46 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
Tokaanu	Transformers - Ground Mounted	Turangi	10S31 Tin shed with Magnefix. Tape up leads. Open LV rack needs replacing.	45k
Whakamaru	Line Renewal	Huirimu	121-02 11kV Line Renewal	110k
Whakamaru	Line Renewal	Tirohanga	129-01 11kV Line Renewal	181k
Whakamaru	Line Renewal	Wharepapa	122-08 11kV Line Renewal	77k
Whakamaru	Line Renewal	Tihoi	124-02 11kV Line Renewal	143k

PROPOSED CAPITAL WORKS: 2012/13				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Whakamaru	Line Renewal	Tirohanga	129-02 11kV Line Renewal	236k
Whakamaru	Line Renewal	Mokai	123-04 LV Line Renewal	7k
Whakamaru	Regulators	Whakamaru Feeder	FED120 Install regulator to lift voltage for irrigation pumps. Install near Kelly's Garage before the river crossing.	101k
Whakamaru	Regulators	Huirimu Feeder	FED121 To hold up voltage with small conductor going east back to Pureora. Needs to be close to ABS 425.	101k
Whakamaru	Substation and 33 kV Development	Whakamaru Feeder	FED310 Regulators at Atiamuri to increase voltage. 33 kV regulator to lift 33 kV voltage levels.	281k
Whakamaru	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information. Year 2 revisit the need for fans.	11k
Whakamaru	Switches	Mokai	493 Automate switch, new pole and ENTEC switch.	34k
Whakamaru	Transformers - Ground Mounted	Mangakino	T706 Install a refurbished 200 kVA transformer.	45k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	159k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	106k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	80k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	86k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	160k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Mahoenui	113-03 11kV Line Renewal	202k
Hangatiki	Line Renewal	Te Mapara	117-04 11kV Line Renewal	299k
Hangatiki	Line Renewal	Te Kuiti Town	105-01 11kV Line Renewal	138k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewal	Rangitoto	106-05 11kV Line Renewal	305k
Hangatiki	Line Renewal	Gravel Scoop	109-04 11kV Line Renewal	318k
Hangatiki	Line Renewal	Piopio	116-05 11kV Line Renewal	133k
Hangatiki	Line Renewal	Oparure	107-05 11kV Line Renewal	221k
Hangatiki	Line Renewal	Oparure	107-06 11kV Line Renewal	221k
Hangatiki	Line Renewal	Gravel Scoop	109-05 11kV Line Renewal	227k
Hangatiki	Line Renewal	Mokau	128-08 LV Line Renewal	7k
Hangatiki	Line Renewal	Mahoenui	113-03 LV Line Renewal	7k
Hangatiki	Switches	Te Kuiti South	730 Add remote communication	23k
Hangatiki	Switches	Te Mapara	1316 Automate Switch	23k
National Park	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
National Park	Substation and 33 kV Development	National Park Point of Supply	ZSub516 Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers and containerise the switchgear for the 11 kV Feeders. This work aligns with the installation of a new modular substation with the switchgear in a container. (See Zone Substations)	675k
National Park	Substation and 33 kV Development	National Park Zone Substation	ZSub501 Rebuild Site. Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	318k
National Park	Switchgear	Chateau	16N17 Add switchgear to this site.	45k
National Park	Transformers - 2 Pole Structures	National Park	15L05 Transformer is close to motel balcony. Ground mount transformer, check loadings for transformer size.	45k
Ohakune	Substation and 33 kV Development	Ohakune Point of Supply	ZSub517 The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. Break into the circuit before the cross bus. Split one feeder off. Have capacity for a spare feeder. Transpower planning includes a new 20 MVA transformer planned for 13/14 years.	169k
Ohakune	Switchgear	Ohakune Town	20L15 Upgrade transformer to transformer with RTE.	45k
Ohakune	Transformers - 2 Pole Structures	Turoa	20M08 Ground mount transformer, check loadings.	56k
Ongarue	Line Renewal	Ongarue	421-02 11kV Line Renewal	202k
Ongarue	Line Renewal	Ohura	413-08 11kV Line Renewal	270k
Ongarue	Line Renewal	Western	403-06 11kV Line Renewal	272k
Ongarue	Line Renewal	Northern	402-05 11kV Line Renewal	336k
Ongarue	Line Renewal	Ongarue / Taumarunui 33	604-01 33kV Line Renewal	500k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Line Renewal	Taumarunui / Kuratau 33	608-03 33kV Line Renewal	240k
Ongarue	Line Renewal	Tuhua 33	602-01 33kV Line Renewal	32k
Ongarue	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Regulators installed on Kuratau supply at Manunui To be done with Manunui rebuild	281k
Ongarue	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Rebuild site. Replace incoming 33 kV Breaker.	169k
Ongarue	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Refurbish transformer.	90k
Ongarue	Substation and 33 kV Development	Manunui Zone Substation	ZSub510 Install oil separation.	28k
Ongarue	Substation and 33 kV Development	Ongarue Point of Supply	ZSub514 Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho; remove Nihoniho breaker. Needs 4 line reclosers and one or two automated 33kV switches. Allows splitting of feeders and isolation of Transpower supply. Some 33kV cabling will be necessary. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	675k
Ongarue	Switches	Hakiaha Feeder	FED401 Low voltage tie between transformers in CBD. Do in conjunction with switchgear for 01A38 and 01A82	113k
Ongarue	Switches	Western	5404 Automate Switch	28k
Ongarue	Switches	Manunui	5914 Automate Switch	34k
Ongarue	Switches	Western	5795 Automate Switch	28k
Ongarue	Switchgear	Hakiaha Feeder	FED401 Add 11 kV switchgear for 01A38 and 01A82	56k
Tokaanu	Switches	Waihaha	5150 Switch Automation	45k
Tokaanu	Transformers - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer. Downsize transformer as required. Rebuild with standard single pole structure.	28k
Tokaanu	Transformers - 2 Pole Structures	Waihaha	07Q14 Rebuild structure. Next to State Highway. Existing equipment below regulation height.	56k
Tokaanu	Transformers - Ground Mounted	Turangi	10S41 Install RTE switch do in conjunction with 10S42.	45k
Tokaanu	Transformers - Ground Mounted	Turangi	10S42 Install front access transformer with11 kV internal fusing. Do in conjunction with 10S41.	45k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Whakamaru	Feeder Development	Mokai Feeder	FED123 Upgrade 11 kV conductor from old regulator site at the beginning of Tirohanga Road to the new substation site near the injection pumps. This work is in conjunction with the new modular substation and 33 kV line. 3 km of line to upgrade to Mink conductor.	309k
Whakamaru	Line Renewal	Wharepapa	122-07 11kV Line Renewal	264k
Whakamaru	Regulators	Wharepapa	122-03 Install regulator on Hingaia Road near T299.	101k
Whakamaru	Regulators	Wharepapa	122-06 Install regulator just after switch 376 on Whatauri Road.	101k
Whakamaru	Substation and 33 kV Development	Tirohanga Road / Marotiri	ZSub3358 Rebuild a new 33 kV line to a new modular substation. Line interconnects with 33 kV line to Marotiri and will be built on Turopaki Trust Land. Substation to be located on Tirohanga Road near Pumps. Work in conjunction with 11 kV conductor upgrade on Tirohanga Rd.	721k
Whakamaru	Substation and 33 kV Development	Tirohanga Road	Install a modular substation on Tirohanga Road near the injection pumps, in conjunction with new 33 kV line and 11 kV upgrade. Approx 100k for switchgear and 400k for modular substation.	515k
Whakamaru	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information. Year 2 revisit the need for fans.	34k
Whakamaru	Switches	Tihoi	454 Automate switch. Replace with ENTEC switch. Will require a new pole and switch.	34k
Whakamaru	Switches	Tirohanga	434 Automate Switch	23k
Whakamaru	Transformers - Ground Mounted	Mangakino	T701 Check loading and replace with a refurbished I tank of a suitable size. Install a RMU with 2 fuses, one for T2316. Spread cost of RMU over T2316.	45k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	159k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	159k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	106k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	80k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Have a semi mobile Load Control plant that can be relocated. Reuse the load control plant that is removed from National Park.	68k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	80k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Load Control	113k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	171k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Caves	101-09 11kV Line Renewal	30k
Hangatiki	Line Renewal	Aria	114-05 11kV Line Renewal	261k
Hangatiki	Line Renewal	Aria	114-04 11kV Line Renewal	161k
Hangatiki	Line Renewal	Benneydale	103-08 11kV Line Renewal	68k
Hangatiki	Line Renewal	Gravel Scoop	109-14 11kV Line Renewal	233k
Hangatiki	Line Renewal	Caves	101-10 11kV Line Renewal	86k
Hangatiki	Line Renewal	Mokauiti	115-05 11kV Line Renewal	204k
Hangatiki	Line Renewal	Mokau	128-09 11kV Line Renewal	99k
Hangatiki	Line Renewal	Mokau	128-08 11kV Line Renewal	484k
Hangatiki	Line Renewal	Otorohanga	112-07 11kV Line Renewal	98k
Hangatiki	Line Renewal	Mahoenui	113-05 11kV Line Renewal	244k
Hangatiki	Line Renewal	Mokauiti	115-06 11kV Line Renewal	155k
Hangatiki	Line Renewal	Gravel Scoop	109-06 11kV Line Renewal	279k
Hangatiki	Line Renewal	Benneydale	103-07 LV Line Renewal	64k
Hangatiki	Switches	Otorohanga	645 Switch Automation	11k
Hangatiki	Switches	Otorohanga	308 Switch Automation	11k
Hangatiki	Transformers - 2 Pole Structures	Te Kuiti South	T559 Rebuild structure, replace poles, use standard single pole if possible.	56k
Hangatiki	Transformers - 2 Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	23k
Hangatiki	Transformers - Ground Mounted	Oparure	T663 Replace with refurbished I tank transformer.	45k
National Park	Line Renewal	National Park	411-02 11kV Line Renewal	401k
National Park	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
National Park	Line Renewal	National Park 33	601-01 33kV Line Renewal	31k
National Park	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Renew fence	56k
National Park	Switchgear	Chateau	16N21 Add 11 kV switchgear to transformer.	45k
National Park	Transformers - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Transformers - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer . ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	30k
National Park	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	45k
Ohakune	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	151k
Ohakune	Regulators	Ohakune Town Feeder	FED414 Regulator at town boundary	107k
Ohakune	Switchgear	Turoa	17N04 Need a visual break & earths. Switchgear needed	45k
Ongarue	Line Renewal	Manunui	407-01 11kV Line Renewal	126k
Ongarue	Line Renewal	Western	403-07 11kV Line Renewal	167k
Ongarue	Line Renewal	Southern	409-07 11kV Line Renewal	167k
Ongarue	Line Renewal	Ohura	413-03 11kV Line Renewal	163k
Ongarue	Line Renewal	Taumarunui / Kuratau 33	608-02 33kV Line Renewal	336k
Ongarue	Line Renewal	Manunui	407-01 LV Line Renewal	32k
Ongarue	Switches	Northern	6127 Switch Automation	28k
Ongarue	Switches	Hakiaha	5831 Switch Automation	34k
Ongarue	Switchgear	Western	08I55 Install a RMU	45k
Ongarue	Transformers - 2 Pole Structures	Manunui	08K14 Replace pole mounted transformer with refurbished ground mounted transformer.	49k
Ongarue	Transformers - 2 Pole Structures	Tuhua	05G03 Lift equipment over regulation height and maintain clearances.	23k
Ongarue	Transformers - 2 Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	49k
Ongarue	Transformers - 2 Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA transformer.	45k
Tokaanu	Switches	Tokaanu / Kuratau 33	5984 Switch Automation	36k
Tokaanu	Switches	Rangipo / Hautu	5207 Install recloser at this site.	45k
Tokaanu	Switchgear	Oruatua Feeder	FED417 Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	158k
Tokaanu	Switchgear	Oruatua	09U11 Install switchgear near or associated with 09U11.	56k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switchgear	Kuratau	08R20 Install transformer with RTE switch.	45k
Tokaanu	Transformers - 2 Pole Structures	Motuoapa	09T04 Replace with ground mounted 300 kVA. Use a refurbished transformer.	56k
Tokaanu	Transformers - 2 Pole Structures	Kuratau	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available.	39k
Tokaanu	Transformers - Ground Mounted	Turangi	10S44 Tin shed roadside. Open LV rack in tin shed, messy layout of leads. Replace with ground mounted transformer.	41k
Whakamaru	Line Renewal	Tihoi	124-03 11kV Line Renewal	104k
Whakamaru	Line Renewal	Huirimu	121-03 11kV Line Renewal	270k
Whakamaru	Switches	Pureora	423 Switch Automation	23k
Whakamaru	Transformers - Ground Mounted	Mangakino	T700 Rebuild to regulations and current TLC standards.	45k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	186k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	186k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Semi mobile containerised 2.5 MVA substation.	450k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	64k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	151k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	310k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Benneydale	103-08 11kV Line Renewal	68k
Hangatiki	Line Renewal	Mahoenui	113-06 11kV Line Renewal	222k
Hangatiki	Line Renewal	Coast	125-06 11kV Line Renewal	179k
Hangatiki	Line Renewal	Rural	126-03 11kV Line Renewal	3k
Hangatiki	Line Renewal	Maihiihi	111-10 11kV Line Renewal	320k
Hangatiki	Line Renewal	Mahoenui	113-07 11kV Line Renewal	107k
Hangatiki	Line Renewal	Coast	125-05 11kV Line Renewal	307k
Hangatiki	Line Renewal	Caves	101-11 11kV Line Renewal	51k
Hangatiki	Line Renewal	Te Mapara	117-06 11kV Line Renewal	221k
Hangatiki	Line Renewal	Coast	125-05 LV Line Renewal	32k
Hangatiki	Regulators	Mokau Feeder	FED128 Near Bolts place on top of hill	101k
Hangatiki	Regulators	Maihiihi	REG06 Replace Whibley Road regulator. This is an old type of regulator and overload when back feeding.	96k
Hangatiki	Substation and 33 kV Development	Taharoa B Feeder	FED302 Renew and remove hazardous equipment. Customer has not made a decision: Coincides with confirmed upgrading of site. Cost to bring reliability to expectations of large 24/7 plant.	112k
Hangatiki	Substation and 33 kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	788k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Replace fence	68k
Hangatiki	Switches	Otorohanga	288 Switch Automation	28k
Hangatiki	Transformers - 2 Pole Structures	Mahoenui	T1865 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
Hangatiki	Transformers - 2 Pole Structures	Te Mapara	T1777 Rebuild structure with transformer higher up pole. Use standard single pole design if practical.	45k
Hangatiki	Transformers - 2 Pole Structures	Mahoenui	T1453 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Hangatiki	Transformers - 2 Pole Structures	Mahoenui	T2520 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Hangatiki	Transformers - Ground Mounted	Waitomo	T406 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Hangatiki East	T381 Replace with I tank or front access transformer. Use a refurbished transformer if available.	45k
National Park	Line Renewal	Raurimu	410-02 11kV Line Renewal	231k
National Park	Line Renewal	No Feeder	610-01 33kV Line Renewal	51k
National Park	Switches	National Park	5151 Automate switch in Substation	45k
Ohakune	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	151k
Ohakune	Line Renewal	Turoa	415-01 11kV Line Renewal	280k
Ohakune	Line Renewal	Ohakune Town	414-01 LV Line Renewal	127k
Ohakune	Line Renewal	Turoa	415-01 LV Line Renewal	106k
Ohakune	Switchgear	Ohakune Town	20L68 Install additional switchgear	90k
Ohakune	Switchgear	Tangiwai	20L43 Install RTE	45k
Ohakune	Switchgear	Ohakune Town	20L59 Install transformer with RTE switch.	45k
Ohakune	Transformers - 2 Pole Structures	Tangiwai	20L06 Replace structure with ground mounted transformer.	62k
Ongarue	Line Renewal	Nihoniho	412-02 11kV Line Renewal	196k
Ongarue	Line Renewal	Ohura	413-09 11kV Line Renewal	127k
Ongarue	Line Renewal	Western	403-07 11kV Line Renewal	167k
Ongarue	Line Renewal	Western	403-03 11kV Line Renewal	141k
Ongarue	Line Renewal	Southern	409-08 11kV Line Renewal	229k
Ongarue	Line Renewal	Ohura	413-04 11kV Line Renewal	286k
Ongarue	Line Renewal	Ongarue	421-03 11kV Line Renewal	206k
Ongarue	Line Renewal	Taumarunui / Kuratau 33	608-01 33kV Line Renewal	208k
Ongarue	Line Renewal	Ongarue	421-03 LV Line Renewal	27k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Install reactive power capacitors.	103k
Ongarue	Switches	Manunui	5912 Switch Automation	34k
Ongarue	Switches	Matapuna	5838 Switch Automation	45k
Ongarue	Transformers - 2 Pole Structures	Hakiaha	01B11 Rebuild structure with safer LV wiring. Raise the height of the transformer.	45k
Ongarue	Transformers - 2 Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer.	45k
Ongarue	Transformers - 2 Pole Structures	Southern	09K50 Check loading on transformer. Either 100 kVA standard single pole or 200 kVA refurbished and mount.	42k
Tokaanu	Line Renewal	Oruatua	417-01 11kV Line Renewal	224k
Tokaanu	Line Renewal	No Feeder	506-01 LV Line Renewal	186k
Tokaanu	Substation and 33 kV Development	Turangi Zone Substation	ZSub505 11 kV breakers to split heavily loaded feeder.	155k
Tokaanu	Switches	Kuratau	6353 Automate recloser.	34k
Tokaanu	Switchgear	Kuratau	09R14 Install Xiria in association with Transformer 09R14 and work on 09R16.	45k
Tokaanu	Switchgear	Kuratau	09R16 Install RTE switch.	45k
Tokaanu	Transformers - 2 Pole Structures	Kuratau	09R27 Lift equipment on pole to above regulation height and maintain clearances.	39k
Tokaanu	Transformers - Ground Mounted	Turangi	10S26 Rebuild to regulations and current TLC standards.	45k
Whakamaru	Line Renewal	Pureora	119-03 11kV Line Renewal	5k
Whakamaru	Line Renewal	Huirimu	121-04 11kV Line Renewal	63k
Whakamaru	Line Renewal	Whakamaru	120-03 11kV Line Renewal	152k
Whakamaru	Line Renewal	Whakamaru	120-03 LV Line Renewal	106k
Whakamaru	Switchgear	Whakamaru Feeder	FED120 RMU and 300 kVA transformer for T2523 and remove T2524 and T2521. Through-joint at T2523 to T2525. Replace LV cable around village with 4c cable, new 16mm N/S street light cable and TUDs pillar boxes. May need to include replacement of service-main to boxes on side of houses.	515k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	186k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	186k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	21k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	159k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	67k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	McDonalds	110-04 11kV Line Renewal	39k
Hangatiki	Line Renewal	Benneydale	103-10 11kV Line Renewal	267k
Hangatiki	Line Renewal	McDonalds	110-03 11kV Line Renewal	84k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewal	Gravel Scoop	109-07 11kV Line Renewal	313k
Hangatiki	Line Renewal	Mokau	128-07 11kV Line Renewal	75k
Hangatiki	Line Renewal	Caves	101-12 11kV Line Renewal	253k
Hangatiki	Line Renewal	Maihiihi	111-11 11kV Line Renewal	146k
Hangatiki	Line Renewal	Aria	114-06 11kV Line Renewal	142k
Hangatiki	Line Renewal	Otorohanga	112-05 11kV Line Renewal	3k
Hangatiki	Line Renewal	Mahoenui	113-08 11kV Line Renewal	217k
Hangatiki	Line Renewal	Maihiihi	109-08 11kV Line Renewal	79k
Hangatiki	Line Renewal	Caves	101-13 11kV Line Renewal	126k
Hangatiki	Line Renewal	Benneydale	103-11 11kV Line Renewal	267k
Hangatiki	Line Renewal	Otorohanga	112-06 11kV Line Renewal	103k
Hangatiki	Line Renewal	Te Waireka Rd 33	303-01 33kV Line Renewal	181k
Hangatiki	Regulators	Rangitoto Feeder	FED106 Regulator towards Otewa Rd, also to pick up Otewa when working on Gravel Scoop and Waipa Gorge	96k
Hangatiki	Substation and 33 kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	56k
Hangatiki	Substation and 33 kV Development	Hangatiki Zone Substation	ZSub204 Install oil separation.	17k
Hangatiki	Switches	McDonalds	387 Automate Switch. Replace pole and install ENTEC.	34k
Hangatiki	Switches	McDonalds	328 Automate Switch. Install a Motor Actuator onto existing ABS.	23k
Hangatiki	Transformers - 2 Pole Structures	Te Mapara	T1829 Check ground clearance - raise transformer on pole.	8k
Hangatiki	Transformers - 2 Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure.	28k
Hangatiki	Transformers - Ground Mounted	Oparure	T457 Install a front access transformer 300 kVA with I Blade RTE switch.	45k
Hangatiki	Transformers - Ground Mounted	Rangitoto	T464 Replace with a refurbished I Tank. Check loading and size transformer appropriately.	45k
National Park	Line Renewal	Raurimu	410-03 11kV Line Renewal	307k
National Park	Line Renewal	National Park / Kuratau 33	609-04 33kV Line Renewal	268k
National Park	Switchgear	Chateau	16N09 Install switchgear	45k
Ohakune	Feeder Development	Turoa	415-01 Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.	53k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Feeder Development	Turoa	415-04 Redesign over LV and HV configuration for Rangatau. Check loading of all transformers including 20M09. Work in association with planned change of two pole structures 20M07 in 12/13 year and 20M08 in 13/14. Assess LV wire size and extending LV. Work to alleviate low voltage problems and possible development of empty sections. Do part in 12/13 and part in year 16/17.	84k
Ohakune	Line Renewal	Ohakune Town	414-01 11kV Line Renewal	213k
Ohakune	Line Renewal	Turoa	415-01 11kV Line Renewal	280k
Ohakune	Line Renewal	Ohakune Town	414-01 LV Line Renewal	127k
Ohakune	Line Renewal	Turoa	415-01 LV Line Renewal	133k
Ohakune	Switches	Tangiwai	6118 Automate Switch	45k
Ohakune	Switches	Turoa	5680 Automate Switch	45k
Ohakune	Switchgear	Tangiwai	20L45 Install a transformer with RTE.	45k
Ohakune	Transformers - 2 Pole Structures	Turoa	20M07 Ground mount transformer. Check loadings.	56k
Ongarue	Line Renewal	Ongarue	421-04 11kV Line Renewal	372k
Ongarue	Line Renewal	Southern	409-09 11kV Line Renewal	179k
Ongarue	Line Renewal	Western	403-04 11kV Line Renewal	97k
Ongarue	Line Renewal	Ongarue	421-03 LV Line Renewal	11k
Ongarue	Substation and 33 kV Development	Borough Zone Substation	ZSub508 Install oil separation.	17k
Ongarue	Transformers - 2 Pole Structures	Western	08I21 Raise equipment on structure to above regulation height for 11 kV from ground level. Maintain clearances.	56k
Ongarue	Transformers - 2 Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	56k
Ongarue	Transformers - 2 Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level.	45k
Ongarue	Transformers - 2 Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure.	42k
Ongarue	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	45k
Tokaanu	Line Renewal	Waiotaka	427-01 11kV Line Renewal	166k
Tokaanu	Line Renewal	Motuoapa	425-01 11kV Line Renewal	101k
Tokaanu	Line Renewal	Motuoapa	425-01 LV Line Renewal	159k
Tokaanu	Switches	Kuratau	6355 Automate Switch	34k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switchgear	Rangipo / Hautu	10S03 Install switchgear	45k
Tokaanu	Transformers - Ground Mounted	Turangi	10S29 Rebuild to regulations and current TLC standards.	41k
Whakamaru	Regulators	Mokai	123-02 Install regulator on Waihora road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	101k
Whakamaru	Substation and 33 kV Development	Whakamaru Feeder	FED310 Install second regulator at Maraetai substation site on 33 kV line.	281k
Whakamaru	Transformers - 2 Pole Structures	Mangakino	T1081 Check loading; rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	56k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	186k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	186k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	6k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	36k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Mokau	128-03 11kV Line Renewal	348k
Hangatiki	Line Renewal	Maihiihi	111-06 11kV Line Renewal	209k
Hangatiki	Line Renewal	Otorohanga	112-01 11kV Line Renewal	324k
Hangatiki	Line Renewal	Benneydale	103-09 11kV Line Renewal	379k
Hangatiki	Line Renewal	Mokau	128-10 11kV Line Renewal	261k
Hangatiki	Line Renewal	Te Kuiti South	104-01 11kV Line Renewal	365k
Hangatiki	Line Renewal	Te Kawa St 33	304-01 33kV Line Renewal	197k
Hangatiki	Line Renewal	Gadsby / Wairere 33	307-03 33kV Line Renewal	275k
Hangatiki	Line Renewal	Otorohanga	112-01 LV Line Renewal	212k
Hangatiki	Line Renewal	Te Kuiti South	104-01 LV Line Renewal	318k
Hangatiki	Substation and 33 kV Development	Waitete Zone Substation	ZSub206 Install modular substation at industrial sites. Funded through on-going charges to industrial customers.	394k
Hangatiki	Substation and 33 kV Development	Oparure Zone Substation	ZSub208 Install bunding, oil separation and earthquake restraints.	45k
Hangatiki	Switches	Otorohanga Feeder	FED112 LV Link T554 toilet block link to adjacent transformers.	113k
Hangatiki	Switches	McDonalds	320 Automate Switch	23k
Hangatiki	Transformers - 2 Pole Structures	Mokau	T2177 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Hangatiki	Transformers - 2 Pole Structures	Te Kuiti South	T478 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T699 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Coast	T547 Rebuild to regulations and current TLC standards.	45k
National Park	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
National Park	Switchgear	National Park	15L07 Install switchgear	45k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Switchgear	Chateau	16N01 Add 11 kV switchgear to transformer.	45k
Ohakune	Regulators	Tangiwai Feeder	FED416 Assumes new Tangiwai supply from Transpower, locate at Rangataua.	107k
Ohakune	Switchgear	Tangiwai	20L44 Install switchgear RMU	45k
Ohakune	Switchgear	Tangiwai	09R11 Install switchgear	45k
Ohakune	Switchgear	Ohakune Town	20L18 Install switchgear	45k
Ohakune	Transformers - 2 Pole Structures	Turoa	20L31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
Ongarue	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
Ongarue	Line Renewal	Ohura	413-07 11kV Line Renewal	136k
Ongarue	Line Renewal	Nihoniho 33	603-02 33kV Line Renewal	302k
Ongarue	Switches	Southern	5136 Automate Switch	45k
Ongarue	Switches	Matapuna	5357 Automate Switch	45k
Ongarue	Transformers - 2 Pole Structures	Western	08H03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - 2 Pole Structures	Ongarue	02K16 Rebuild structure 11 kV bushing are below regulation height.	56k
Ongarue	Transformers - 2 Pole Structures	Ohura	07D08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - Ground Mounted	Matapuna	01B24 Rebuild to regulations and current TLC standards.	45k
Tokaanu	Line Renewal	Kuratau	406-03 11kV Line Renewal	239k
Tokaanu	Line Renewal	Kuratau	406-03 LV Line Renewal	106k
Tokaanu	Switches	Kuratau	5921 Automate Switch	34k
Tokaanu	Switchgear	Waihaha	07R13 Install RMU	45k
Tokaanu	Transformers - Ground Mounted	Turangi	10S39 Rebuild to regulations and current TLC standards.	45k
Whakamaru	Feeder Development	Mokai Feeder	FED123 Re-conductor Tirohanga Road from new substation site near injection pumps to Okama Rd. 7 km of line to Mink. This allows for better back feed options and more security of supply.	721k
Whakamaru	Line Renewal	Wharepapa	122-01 11kV Line Renewal	235k
Whakamaru	Line Renewal	Wharepapa	122-02 11kV Line Renewal	462k
Whakamaru	Line Renewal	Whakamaru	120-01 11kV Line Renewal	339k
Whakamaru	Line Renewal	Mangakino	118-01 11kV Line Renewal	364k
Whakamaru	Line Renewal	Mangakino	118-01 LV Line Renewal	133k
Whakamaru	Regulators	Pureora Feeder	FED119 Close to Crusaders Meats 4th Regulator for deer plant.	96k
Whakamaru	Switches	Mangakino	463 Automate Switch	23k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	186k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	186k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	186k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	16k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Aria	114-01 11kV Line Renewal	233k
Hangatiki	Line Renewal	Rangitoto	106-07 11kV Line Renewal	276k
Hangatiki	Line Renewal	Rangitoto	106-02 11kV Line Renewal	30k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewal	Te Kuiti South	104-02 11kV Line Renewal	350k
Hangatiki	Line Renewal	Oparure	107-08 11kV Line Renewal	207k
Hangatiki	Line Renewal	Rangitoto	106-01 11kV Line Renewal	160k
Hangatiki	Line Renewal	Benneydale	103-09 11kV Line Renewal	379k
Hangatiki	Line Renewal	Taharoa B 33	302-01 33kV Line Renewal	554k
Hangatiki	Line Renewal	Gadsby / Wairere 33	307-01 33kV Line Renewal	121k
Hangatiki	Line Renewal	Aria	114-01 LV Line Renewal	21k
Hangatiki	Line Renewal	Rangitoto	106-01 LV Line Renewal	127k
Hangatiki	Line Renewal	Rangitoto	106-07 LV Line Renewal	16k
Hangatiki	Regulators	Mokau Feeder	FED128 Before Mokau at old killing house site.	101k
Hangatiki	Substation and 33 kV Development	Taharoa A Feeder	FED301 Upgrade line to higher transmission voltage and capacity.	337k
Hangatiki	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Refurbish transformer (T1)	90k
Hangatiki	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Install oil separation.	17k
Hangatiki	Switches	Hangatiki East	336 Automate Switch	39k
Hangatiki	Transformers - 2 Pole Structures	Mahoenui	T1692 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Hangatiki	Transformers - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design.	45k
Hangatiki	Transformers - 2 Pole Structures	Mokau	T2194 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	6k
Hangatiki	Transformers - Ground Mounted	Oparure	T9 Rebuild to regulations and current TLC standards.	45k
National Park	Line Renewal	National Park	411-01 11kV Line Renewal	147k
National Park	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
National Park	Line Renewal	Chateau	419-01 11kV Line Renewal	143k
National Park	Line Renewal	National Park	411-01 LV Line Renewal	191k
National Park	Switchgear	Chateau	16N02 Add 11 kV switchgear to transformer.	45k
National Park	Transformers - 2 Pole Structures	National Park	16L02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
National Park	Transformers - Ground Mounted	Chateau	16N05 Rebuild to regulations and current TLC standards.	45k
Ohakune	Switchgear	Ohakune Town	T4199 Install switchgear	45k
Ohakune	Switchgear	Tangiwai	20L46 Install switchgear, RMU.	45k
Ohakune	Transformers - 2 Pole Structures	Turoa	20M01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	51k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Line Renewal	Southern	409-01 11kV Line Renewal	339k
Ongarue	Line Renewal	Manunui	408-01 11kV Line Renewal	302k
Ongarue	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
Ongarue	Line Renewal	Nihoniho 33	603-01 33kV Line Renewal	273k
Ongarue	Line Renewal	Manunui	408-01 LV Line Renewal	111k
Ongarue	Switches	Matapuna	1.5 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU.	26k
Ongarue	Switches	Matapuna	1.6 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU	26k
Ongarue	Switches	Matapuna	1.7 RMU Grandstand Replace 1.5, 1.6, 1.7 to new type RMU	26k
Ongarue	Transformers - 2 Pole Structures	Hakiaha	01A31 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - 2 Pole Structures	Manunui	08J07 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - 2 Pole Structures	Southern	11K11 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - Ground Mounted	Matapuna	01A70 Rebuild to regulations and current TLC standards.	45k
Tokaanu	Line Renewal	Tokaanu	420-01 11kV Line Renewal	29k
Tokaanu	Line Renewal	No Feeder	507-01 LV Line Renewal	53k
Tokaanu	Switches	Kuratau	6557 Automate Switch	34k
Tokaanu	Switchgear	Kuratau	10S41 Install switchgear	45k
Tokaanu	Transformers - Ground Mounted	Rangipo / Hautu	11S16 Rebuild to regulations and current TLC standards.	3k
Tokaanu	Transformers - Ground Mounted	Motuoapa	T4104 Rebuild to regulations and current TLC standards.	3k
Tokaanu	Transformers - Ground Mounted	Turangi	10S24 Rebuild to regulations and current TLC standards.	3k
Tokaanu	Transformers - Ground Mounted	Kuratau	08R22 Rebuild to regulations and current TLC standards.	3k
Whakamaru	Line Renewal	Wharepapa	122-06 11kV Line Renewal	292k
Whakamaru	Line Renewal	Whakamaru	120-02 11kV Line Renewal	221k
Whakamaru	Line Renewal	Wharepapa	122-03 11kV Line Renewal	255k
Whakamaru	Line Renewal	Wharepapa	122-04 11kV Line Renewal	248k
Whakamaru	Substation and 33 kV Development	Mokai Point of Supply	ZSub3358 Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	394k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Load Control	113k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Feeder Development	Mokau Feeder	FED128 Mokau Generator. Add remotely controlled diesel gas injection for holiday periods and during shutdown interruptions.	338k
Hangatiki	Line Renewal	Coast	125-01 11kV Line Renewal	270k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewal	Piopio	116-02 11kV Line Renewal	186k
Hangatiki	Line Renewal	Mahoenui	113-01 11kV Line Renewal	213k
Hangatiki	Line Renewal	Te Mapara	117-01 11kV Line Renewal	301k
Hangatiki	Line Renewal	Mokauiti	115-01 11kV Line Renewal	129k
Hangatiki	Line Renewal	Piopio	116-01 11kV Line Renewal	406k
Hangatiki	Line Renewal	Taharoa A 33	301-01 33kV Line Renewal	554k
Hangatiki	Line Renewal	Waitete 33	306-01 33kV Line Renewal	233k
Hangatiki	Line Renewal	Gadsby / Wairere 33	307-03 33kV Line Renewal	275k
Hangatiki	Line Renewal	Piopio	116-02 LV Line Renewal	133k
Hangatiki	Line Renewal	Coast	125-01 LV Line Renewal	5k
Hangatiki	Regulators	Piopio Feeder	FED116 Prior to Piopio township.	96k
Hangatiki	Regulators	Mahoenui Feeder	FED113 Mainly for backup of Mokau Feeder when 33 kV is out.	96k
Hangatiki	Substation and 33 kV Development	Taharoa A Feeder	FED301 Upgrade line to higher transmission voltage and capacity.	337k
Hangatiki	Switches	Maihiihi	127 Replace Recloser	45k
Hangatiki	Switches	Hangatiki East	361 Automate Switch	23k
Hangatiki	Switches	Mahoenui	1343 Replace Recloser	45k
Hangatiki	Transformers - 2 Pole Structures	Tihoi	T1618 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
Hangatiki	Transformers - Ground Mounted	Mokau	T2155 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Mokau	T2154 Transformer upgrade.	45k
Hangatiki	Transformers - Ground Mounted	Mokau	T2140 Transformer upgrade.	45k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	45k
Hangatiki	Transformers - Ground Mounted	Coast	T640 Rebuild to regulations and current TLC standards.	45k
National Park	Line Renewal	Raurimu	410-04 11kV Line Renewal	118k
National Park	Line Renewal	Chateau	419-01 11kV Line Renewal	143k
National Park	Line Renewal	National Park / Kuratau 33	609-03 33kV Line Renewal	576k
National Park	Substation and 33 kV Development	Tawhai Zone Substation	ZSub513 Install a second transformer. Use a Transformer out of Turangi.	675k
National Park	Switchgear	Chateau	16N28 Add 11 kV switchgear to transformer.	45k
National Park	Switchgear	Chateau	16N29 Add 11 kV switchgear to transformer.	45k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Transformers - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transfer structure to make safer. Investigate a refurnished 33 kV / 400 v transformer. A lot of children visit this area, structure needs to be made safe.	62k
Ohakune	Line Renewal	Turoa	415-04 11kV Line Renewal	101k
Ohakune	Transformers - 2 Pole Structures	Turoa	20L19 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	79k
Ongarue	Line Renewal	Manunui	408-02 11kV Line Renewal	396k
Ongarue	Line Renewal	Tuhua	422-03 11kV Line Renewal	125k
Ongarue	Line Renewal	Northern	402-01 11kV Line Renewal	597k
Ongarue	Line Renewal	Southern	409-01 11kV Line Renewal	339k
Ongarue	Line Renewal	Northern	402-01 LV Line Renewal	212k
Ongarue	Line Renewal	Manunui	408-02 LV Line Renewal	27k
Ongarue	Transformers - 2 Pole Structures	Southern	10K14 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Ongarue	Transformers - 2 Pole Structures	Nihoniho	06E01 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Ongarue	Transformers - 2 Pole Structures	Matapuna	01A75 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	45k
Ongarue	Transformers - 2 Pole Structures	Manunui	08J10 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	7k
Ongarue	Transformers - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	51k
Tokaanu	Feeder Development	Waihaha Feeder	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	225k
Tokaanu	Switches	Turangi	5209 Install Xiria Switch or similar at this point.	68k
Tokaanu	Switches	Hirangi	6186 Install remote control on this switch so can tie Turangi and Hirangi feeders together.	11k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switches	Turangi Feeder	FED423 Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40.	281k
Whakamaru	Line Renewal	Huirimu	121-01 11kV Line Renewal	245k
Whakamaru	Line Renewal	Tihoi	124-00 11kV Line Renewal	10k
Whakamaru	Line Renewal	Tihoi	124-01 11kV Line Renewal	166k
Whakamaru	Line Renewal	Whakamaru	120-05 11kV Line Renewal	56k
Whakamaru	Line Renewal	Whakamaru 33	310-01 33kV Line Renewal	118k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Caves	101-04 11kV Line Renewal	85k
Hangatiki	Line Renewal	Mokau	128-05 11kV Line Renewal	184k
Hangatiki	Line Renewal	Rural	126-01 11kV Line Renewal	75k
Hangatiki	Line Renewal	Caves	101-03 11kV Line Renewal	42k
Hangatiki	Line Renewal	Caves	101-02 11kV Line Renewal	71k
Hangatiki	Line Renewal	Caves	101-01 11kV Line Renewal	168k
Hangatiki	Line Renewal	Caves	101-05 11kV Line Renewal	87k
Hangatiki	Line Renewal	Mokau	128-02 11kV Line Renewal	203k
Hangatiki	Line Renewal	Caves	101-07 11kV Line Renewal	50k
Hangatiki	Line Renewal	Caves	101-06 11kV Line Renewal	66k
Hangatiki	Line Renewal	Caves	101-08 11kV Line Renewal	34k
Hangatiki	Line Renewal	Gadsby Rd 33	305-02 33kV Line Renewal	248k
Hangatiki	Line Renewal	Gadsby / Wairere 33	307-02 33kV Line Renewal	92k
Hangatiki	Line Renewal	Mokau	128-02 LV Line Renewal	27k
Hangatiki	Line Renewal	Rural	126-01 LV Line Renewal	5k
Hangatiki	Line Renewal	Mokau	128-05 LV Line Renewal	93k
Hangatiki	Regulators	Mokauiti	115-03 Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	96k
Hangatiki	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Renew switchgear and improve protection schemes.(33 kV)	338k
Hangatiki	Substation and 33 kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T2). Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.	90k
Hangatiki	Switches	Mahoenui	1512 Upgrade recloser	45k
Hangatiki	Transformers - Ground Mounted	Te Kuiti South	T10 Rebuild to regulations and current TLC standards.	56k
Hangatiki	Transformers - Ground Mounted	Gravel Scoop	T1007 Rebuild to regulations and current TLC standards.	56k
Hangatiki	Transformers - Ground Mounted	Rural	T1390 Rebuild to regulations and current TLC standards.	45k
National Park	Line Renewal	Otukou	418-01 11kV Line Renewal	335k
National Park	Line Renewal	National Park / Kuratau 33	609-01 33kV Line Renewal	266k
National Park	Line Renewal	Otukou	418-01 LV Line Renewal	64k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Switches	National Park	5146 Install recloser	45k
National Park	Switchgear	Chateau	15N11 Add 11 kV switchgear to transformer.	45k
National Park	Transformers - 2 Pole Structures	Otukou	12O01 Renew Structure. This transformer needs to be checked for loading.	39k
Ohakune	Feeder Development	Ohakune Town Feeder	FED414 Install under ground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm Al XLPE.	103k
Ohakune	Feeder Development	Turoa	415-04 This is for the re-conductoring of the feeder tie to Tangiwai between switch 5695 to 6323 & 6324 to 5680. Upgrade conductor to Mink or equivalent AAAC.	567k
Ohakune	Line Renewal	Turoa	415-04 11kV Line Renewal	88k
Ohakune	Switches	Turoa	5695 Automate Switch	45k
Ohakune	Switchgear	Turoa	17N01 Install switchgear	45k
Ongarue	Line Renewal	Matapuna	404-01 11kV Line Renewal	521k
Ongarue	Line Renewal	Northern	402-02 11kV Line Renewal	584k
Ongarue	Line Renewal	Manunui	408-02 11kV Line Renewal	396k
Ongarue	Line Renewal	Southern	409-05 11kV Line Renewal	331k
Ongarue	Line Renewal	Matapuna	404-01 LV Line Renewal	338k
Ongarue	Regulators	Ohura Feeder	FED413 One regulator for Ohura assuming that the coal mine venture goes ahead.	96k
Ongarue	Switchgear	Northern	01A52 Install switchgear	45k
Ongarue	Transformers - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	49k
Ongarue	Transformers - 2 Pole Structures	Southern	09K02 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Ongarue	Transformers - 2 Pole Structures	Ohura	07D03 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Tokaanu	Feeder Development	Kuratau Feeder	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	56k
Tokaanu	Line Renewal	Waihaha	426-01 11kV Line Renewal	11k
Tokaanu	Line Renewal	Waihaha	426-02 11kV Line Renewal	109k
Tokaanu	Line Renewal	Tokaanu / Kuratau 33	607-02 33kV Line Renewal	296k
Tokaanu	Switchgear	Rangipo / Hautu Feeder	FED424 Hazard from Genesis 33 kV line crossing.	56k
Tokaanu	Transformers - 2 Pole Structures	Waihaha	04Q06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Transformers - 2 Pole Structures	Oruatua	09U12 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
Whakamaru	Line Renewal	Whakamaru 33	310-03 33kV Line Renewal	269k
Whakamaru	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Diversify off site with a modular substation near Ranganui Road.	450k
Whakamaru	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Replace due to age reliability and condition with new type of circuit breaker.	84k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Te Mapara	117-02 11kV Line Renewal	207k
Hangatiki	Line Renewal	Maihiihi	111-01 11kV Line Renewal	62k
Hangatiki	Line Renewal	Maihiihi	111-03 11kV Line Renewal	162k
Hangatiki	Line Renewal	Maihiihi	111-10 11kV Line Renewal	83k
Hangatiki	Line Renewal	Maihiihi	111-02 11kV Line Renewal	67k
Hangatiki	Line Renewal	Maihiihi	111-04 11kV Line Renewal	232k
Hangatiki	Line Renewal	Gadsby Rd 33	305-03 33kV Line Renewal	59k
Hangatiki	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	266k
Hangatiki	Line Renewal	Taharoa B 33	302-02 33kV Line Renewal	478k
Hangatiki	Line Renewal	Maihiihi	111-02 LV Line Renewal	95k
Hangatiki	Line Renewal	Maihiihi	111-01 LV Line Renewal	32k
Hangatiki	Line Renewal	Maihiihi	111-00 LV Line Renewal	13k
Hangatiki	Substation and 33 kV Development	Hangatiki Zone Substation	ZSub204 Diversify and encourage industrials downstream to install 33/11kV modular substations on their sites. Oyma container sub. Customer funds costs through on-going charges.	394k
Hangatiki	Switches	Waitomo	182 Automate Switch	23k
Hangatiki	Transformers - 2 Pole Structures	Caves	T1185 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Oparure	T1043 Rebuild to regulations and current TLC standards.	56k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T170 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Rural	T1367 Rebuild to regulations and current TLC standards.	45k
National Park	Feeder Development	Chateau Feeder	FED419 Cable from Tavern to Water Tower, 2nd Cable.	338k
National Park	Line Renewal	National Park / Kuratau 33	609-02 33kV Line Renewal	548k
National Park	Switchgear	Chateau	08I03 Add 11 kV switchgear to transformer	45k
National Park	Transformers - 2 Pole Structures	Raurimu	T4077 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ohakune	Switchgear	Turoa	17N02 Install switchgear	45k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Switchgear	Turoa Feeder	FED415 Mechanical cable protection required for cable to ski fields as it is beside the road and inadequately protected.	68k
Ongarue	Line Renewal	Tuhua	422-01 11kV Line Renewal	541k
Ongarue	Line Renewal	Manunui	408-03 11kV Line Renewal	139k
Ongarue	Line Renewal	Northern	402-03 11kV Line Renewal	402k
Ongarue	Line Renewal	Tuhua	422-01 LV Line Renewal	10k
Ongarue	Regulators	Northern Feeder	FED402 By High School Depends on load growth.	96k
Ongarue	Regulators	Ongarue	421-01 Install Regulator at State Highway 4 near switch 6640.	96k
Ongarue	Substation and 33 kV Development	Borough Zone Substation	ZSub508 Diversify with modular substations. Container substation above slip on main road.	377k
Ongarue	Switches	Hakiaha	5.19 Install Recloser	45k
Tokaanu	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
Tokaanu	Substation and 33 kV Development	Kuratau Zone Substation	ZSub509 Put in a modular substation at end of network close to an existing 33kV line.	450k
Tokaanu	Switchgear	Kuratau	08R08 Install switchgear	45k
Tokaanu	Switchgear	Turangi	10S38 Install switchgear	45k
Tokaanu	Transformers - 2 Pole Structures	Kuratau	09R28 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Whakamaru	Line Renewal	Pureora	119-02 11kV Line Renewal	673k
Whakamaru	Line Renewal	Whakamaru	120-04 11kV Line Renewal	866k
Whakamaru	Line Renewal	Whakamaru	120-02 LV Line Renewal	106k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Piopio	116-04 11kV Line Renewal	456k
Hangatiki	Line Renewal	Maihiihi	111-12 11kV Line Renewal	250k
Hangatiki	Line Renewal	Maihiihi	111-05 11kV Line Renewal	136k
Hangatiki	Line Renewal	Oparure	107-03 11kV Line Renewal	119k
Hangatiki	Line Renewal	Oparure	107-07 11kV Line Renewal	329k
Hangatiki	Line Renewal	McDonalds	110-01 11kV Line Renewal	41k
Hangatiki	Line Renewal	Hangatiki East	102-01 11kV Line Renewal	117k
Hangatiki	Line Renewal	Hangatiki East	102-02 11kV Line Renewal	166k
Hangatiki	Line Renewal	Oparure	107-04 11kV Line Renewal	316k
Hangatiki	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	133k
Hangatiki	Line Renewal	Oparure	107-04 LV Line Renewal	8k
Hangatiki	Line Renewal	Gravel Scoop	109-10 LV Line Renewal	64k
Hangatiki	Line Renewal	Gravel Scoop	109-01 LV Line Renewal	42k
Hangatiki	Line Renewal	McDonalds	110-01 LV Line Renewal	13k
Hangatiki	Substation and 33 kV Development	Gadsby Road Zone Substation	ZSub205 Modify existing site by installing better earthquake restraints.	34k
Hangatiki	Switches	Gravel Scoop	304 Install Automated Feeder tie	28k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Transformers - Ground Mounted	Rural	T1559 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Benneydale	T2598 Rebuild to regulations and current TLC standards.	45k
National Park	Switchgear	Chateau	08I34 Add 11 kV switchgear to transformer	45k
Ohakune	Line Renewal	Tangiwai	416-02 11kV Line Renewal	67k
Ohakune	Line Renewal	Tangiwai	416-01 11kV Line Renewal	187k
Ohakune	Line Renewal	Tangiwai	416-02 LV Line Renewal	93k
Ongarue	Line Renewal	Southern	409-04 11kV Line Renewal	60k
Ongarue	Line Renewal	Southern	409-03 11kV Line Renewal	96k
Ongarue	Line Renewal	Northern	402-04 11kV Line Renewal	247k
Ongarue	Line Renewal	Ohura	413-02 11kV Line Renewal	316k
Ongarue	Line Renewal	Southern	409-02 11kV Line Renewal	95k
Ongarue	Line Renewal	Southern	409-02 LV Line Renewal	53k
Ongarue	Line Renewal	Southern	409-04 LV Line Renewal	93k
Ongarue	Line Renewal	Ohura	413-02 LV Line Renewal	127k
Ongarue	Line Renewal	Southern	409-03 LV Line Renewal	53k
Ongarue	Regulators	Western	403-02 Install regulation to accommodate increased load due to the subdivisions of land for lifestyle blocks along River Road and the surround areas.	96k
Ongarue	Regulators	Ohura Feeder	FED413 Second Regulator assuming coal mine goes ahead.	96k
Ongarue	Switches	Ohura	5758 Upgrade sectionaliser to modern type of recloser.	45k
Ongarue	Transformers - 2 Pole Structures	Ohura	07D16 Replace with standard single pole isolating SWER structure.	39k
Ongarue	Transformers - 2 Pole Structures	Southern	12K08 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	39k
Ongarue	Transformers - 2 Pole Structures	Ohura	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	39k
Ongarue	Transformers - Ground Mounted	Northern	T4025 Rebuild to regulations and current TLC standards.	45k
Tokaanu	Feeder Development	Kuratau Feeder	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	56k
Tokaanu	Feeder Development	Waihaha Feeder	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	169k
Tokaanu	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Line Renewal	Rangipo / Hautu	424-02 11kV Line Renewal	111k
Tokaanu	Line Renewal	Kuratau	406-02 11kV Line Renewal	262k
Tokaanu	Line Renewal	Kuratau	406-02 LV Line Renewal	127k
Tokaanu	Switches	Rangipo / Hautu	5963 Upgrade recloser to modern equivalent.	39k
Tokaanu	Switchgear	Rangipo / Hautu	10S13 Install switchgear	45k
Tokaanu	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Rebuild to regulations and current TLC standards.	45k
Whakamaru	Line Renewal	Whakamaru	120-06 11kV Line Renewal	142k
Whakamaru	Substation and 33 kV Development	Atiamuri Point of Supply	ZSub215 Supply from Transpower at Whakamaru on the 220 kV or Mokai's 110 kV supply connection at Whakamaru.	1126k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Gravel Scoop	109-02 11kV Line Renewal	142k
Hangatiki	Line Renewal	Te Mapara	117-03 11kV Line Renewal	227k
Hangatiki	Line Renewal	Gravel Scoop	109-01 11kV Line Renewal	17k
Hangatiki	Line Renewal	Mokau	128-01 11kV Line Renewal	547k
Hangatiki	Line Renewal	Gravel Scoop	109-03 11kV Line Renewal	185k
Hangatiki	Line Renewal	Taharoa A 33	301-02 33kV Line Renewal	133k
Hangatiki	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Refurbish transformer	56k
Hangatiki	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Increase the height of the oil bund and install oil separation.	17k
Hangatiki	Switches	Otorohanga	316 Change switch to a recloser.	45k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T1552 Rebuild to regulations and current TLC standards.	56k
National Park	Substation and 33 kV Development	Otukou Zone Substation	ZSub512 Modify existing site by installing bunding, oil separation and earthquake restraints.	68k
National Park	Switchgear	Chateau	15N02 Add 11 kV switchgear to transformer	45k
National Park	Transformers - 2 Pole Structures	National Park	15K06 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	56k
National Park	Transformers - Ground Mounted	Otukou	12N08 Renew with modern equivalent	45k
National Park	Transformers - Ground Mounted	Chateau	16N04 Rebuild to regulations and current TLC standards.	28k
Ohakune	Line Renewal	Tangiwai	416-03 11kV Line Renewal	222k
Ohakune	Line Renewal	Tangiwai	416-03 LV Line Renewal	27k
Ongarue	Line Renewal	Northern	402-04 11kV Line Renewal	247k
Ongarue	Line Renewal	Ohura	413-01 11kV Line Renewal	133k
Ongarue	Line Renewal	Manunui	408-04 11kV Line Renewal	231k
Ongarue	Line Renewal	Manunui	408-04 LV Line Renewal	27k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Switches	Hakiaha Feeder	FED401 Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	131k
Ongarue	Switches	Northern	5119 Upgrade recloser to new type.	45k
Ongarue	Switches	Northern	5164 Upgrade recloser to new type of equipment.	45k
Ongarue	Switchgear	Northern	07I14 Install switchgear	45k
Ongarue	Transformers - 2 Pole Structures	Ohura	09C05 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards.	45k
Ongarue	Transformers - Ground Mounted	Northern	07I12 Rebuild to regulations and current TLC standards.	45k
Ongarue	Transformers - Ground Mounted	Matapuna	01A36 Rebuild to regulations and current TLC standards.	56k
Tokaanu	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
Tokaanu	Substation and 33 kV Development	Lake Taupo Feeder	FED606 Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues.	338k
Whakamaru	Feeder Development	Tirohanga Feeder	FED129 More Feeder ties and a new modular substation at Mine road.	506k
Whakamaru	Line Renewal	Mokai	123-02 11kV Line Renewal	269k
Whakamaru	Line Renewal	Mokai	123-00 11kV Line Renewal	26k
Whakamaru	Line Renewal	Tirohanga	129-03 11kV Line Renewal	257k
Whakamaru	Line Renewal	Mokai	123-04 11kV Line Renewal	95k
Whakamaru	Line Renewal	Mokai	123-01 11kV Line Renewal	356k
Whakamaru	Line Renewal	Whakamaru 33	310-04 33kV Line Renewal	375k
Whakamaru	Regulators	Pureora Feeder	FED119 Near switch 785 just after Ranganui Road on SH 30.	96k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Load Control	113k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Coast	125-02 11kV Line Renewal	314k
Hangatiki	Line Renewal	Te Mapara	117-05 11kV Line Renewal	212k
Hangatiki	Line Renewal	Piopio	116-03 11kV Line Renewal	72k
Hangatiki	Line Renewal	Otorohanga	112-02 11kV Line Renewal	63k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewal	Otorohanga	112-03 11kV Line Renewal	158k
Hangatiki	Line Renewal	Coast	125-04 11kV Line Renewal	191k
Hangatiki	Line Renewal	Rangitoto	106-04 11kV Line Renewal	500k
Hangatiki	Line Renewal	Mahoenui 33	309-02 33kV Line Renewal	121k
Hangatiki	Line Renewal	Mahoenui 33	309-01 33kV Line Renewal	121k
Hangatiki	Line Renewal	Gadsby Rd 33	305-01 33kV Line Renewal	262k
Hangatiki	Regulators	Caves Feeder	FED101 Depends on tourism growth in area.	96k
Hangatiki	Substation and 33 kV Development	Gadsby / Wairere Feeder	FED307 Allow for full output of proposed schemes. Install additional regulators at Wairere to pull down voltage.	281k
Hangatiki	Switches	Rangitoto	224 Install a recloser	45k
National Park	Feeder Development	Chateau Feeder	FED419 Add second cable from Tawhai to Tavern	563k
National Park	Switchgear	Chateau	15N09 Add 11 kV switchgear to transformer	45k
National Park	Transformers - Ground Mounted	Chateau	16N06 Rebuild to regulations and current TLC standards.	51k
National Park	Transformers - Ground Mounted	Chateau	16N07 Rebuild to regulations and current TLC standards.	51k
Ohakune	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k
Ongarue	Line Renewal	Western	403-02 11kV Line Renewal	460k
Ongarue	Line Renewal	Western	403-01 11kV Line Renewal	23k
Ongarue	Line Renewal	Manunui	408-05 11kV Line Renewal	346k
Ongarue	Line Renewal	Nihoniho	412-01 11kV Line Renewal	233k
Ongarue	Line Renewal	Western	403-01 LV Line Renewal	74k
Ongarue	Substation and 33 kV Development	Nihoniho Zone Substation	ZSub503 Replace fence and upgrade transformer.	225k
Ongarue	Substation and 33 kV Development	Tuhua Zone Substation	ZSub502 Replace with modular substation.	382k
Ongarue	Switchgear	Western	08I31 Install RMU	45k
Ongarue	Switchgear	Northern	08I19 Install switchgear	45k
Ongarue	Transformers - 2 Pole Structures	Ohura	07D11 Rebuild structure with standard single pole isolating SWER transformer structure.	39k
Ongarue	Transformers - 2 Pole Structures	Ohura	T4130 Rebuild site, two SWER transformers. On site visit needed for design. Cost split between T4130 and 10E09.	39k
Tokaanu	Line Renewal	Waihaha	426-03 11kV Line Renewal	361k
Tokaanu	Switches	Turangi Feeder	FED423 Develop LV links through the town.	113k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switchgear	Rangipo / Hautu	10S49 11 kV Cable hard on to 11 kV line, replace pole fit DDO's or Vertical ABS and fuses.	23k
Tokaanu	Transformers - Ground Mounted	Turangi	10S30 Rebuild to regulations and current TLC standards.	41k
Tokaanu	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Rebuild to regulations and current TLC standards.	34k
Whakamaru	Line Renewal	Whakamaru 33	310-02 33kV Line Renewal	1372k
Whakamaru	Regulators	Mokai Feeder	FED123 Replace Tirohanga Road regulator.	107k
Whakamaru	Switches	Mokai	446 Upgrade recloser to modern equivalent.	45k
Whakamaru	Switches	Mokai	474 Upgrade recloser to modern equivalent.	45k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Have mobile generators to support loads. Upgrade existing generator.	169k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Mahoenui	113-02 11kV Line Renewal	53k
Hangatiki	Line Renewal	McDonalds	110-02 11kV Line Renewal	155k
Hangatiki	Line Renewal	Aria	114-02 11kV Line Renewal	84k
Hangatiki	Line Renewal	Maihiihi	111-09 11kV Line Renewal	73k
Hangatiki	Line Renewal	Benneydale	103-03 11kV Line Renewal	10k
Hangatiki	Line Renewal	Benneydale	103-01 11kV Line Renewal	5k
Hangatiki	Line Renewal	Waitomo	108-02 11kV Line Renewal	145k
Hangatiki	Line Renewal	Rangitoto	106-06 11kV Line Renewal	447k
Hangatiki	Line Renewal	Benneydale	103-02 11kV Line Renewal	11k
Hangatiki	Line Renewal	Waitomo	108-01 11kV Line Renewal	56k
Hangatiki	Line Renewal	Mokauiti	115-02 11kV Line Renewal	165k
Hangatiki	Line Renewal	Maihiihi	109-09 11kV Line Renewal	114k
Hangatiki	Regulators	Gravel Scoop Feeder	FED109 Otewa road just before Barber. Will mainly be used when tying to Rangitoto and Maihiihi.	96k
Hangatiki	Substation and 33 kV Development	Mahoenui Feeder	FED309 Built out 33 kV line as load grows in Mokau area.	675k
Hangatiki	Substation and 33 kV Development	Mahoenui Zone Substation	ZSub209 Replace fault thrower with CB 33 kV.	68k
Hangatiki	Switches	Mokau	1626 Change sectionaliser to recloser.	45k
Hangatiki	Switches	Te Kuiti South	242 Automate Switch	23k
Hangatiki	Transformers - Ground Mounted	Te Kuiti South	T1447 Rebuild to regulations and current TLC standards.	34k
National Park	Line Renewal	National Park	411-03 11kV Line Renewal	295k
National Park	Line Renewal	Raurimu	410-01 11kV Line Renewal	355k
National Park	Line Renewal	Raurimu	410-01 LV Line Renewal	48k
Ohakune	Line Renewal	Turoa	415-01 11kV Line Renewal	561k
Ohakune	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Transformers - 2 Pole Structures	Tangiwai	20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	56k
Ongarue	Line Renewal	Hakiaha	401-02 11kV Line Renewal	122k
Ongarue	Regulators	Southern Feeder	FED409 Growth in dairying and irrigation along state highway just before Otapouri road. Will help lift voltage at Owhanga for subdivision growth.	101k
Ongarue	Switches	Ongarue	5462 Change sectionaliser to recloser.	45k
Ongarue	Transformers - Ground Mounted	Northern	01A48 Rebuild to regulations and current TLC standards.	56k
Ongarue	Transformers - Ground Mounted	Matapuna	01B25 Rebuild to regulations and current TLC standards.	34k
Ongarue	Transformers - Ground Mounted	Matapuna	01B21 Rebuild to regulations and current TLC standards.	34k
Ongarue	Transformers - Ground Mounted	Matapuna	01B20 Rebuild to regulations and current TLC standards.	34k
Ongarue	Transformers - Ground Mounted	Western	08I08 Rebuild to regulations and current TLC standards.	34k
Tokaanu	Line Renewal	Rangipo / Hautu	424-01 11kV Line Renewal	391k
Tokaanu	Line Renewal	Turangi 33	605-01 33kV Line Renewal	80k
Tokaanu	Line Renewal	Lake Taupo 33	606-02 33kV Line Renewal	67k
Tokaanu	Line Renewal	Hirangi	405-01 LV Line Renewal	48k
Tokaanu	Line Renewal	Rangipo / Hautu	424-01 LV Line Renewal	221k
Whakamaru	Line Renewal	Mokai	123-03 11kV Line Renewal	324k
Whakamaru	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Install modular substation on Sandel Road in Whakamaru.	450k
Whakamaru	Substation and 33 kV Development	Maraetai Zone Substation	ZSub210 Replace breaker due to age, reliability and condition.	66k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	General Connections - Earthing and tap-offs	265k
Non Specific	Customer Driven Projects	Various	General Connections - Transformers	265k
Non Specific	Customer Driven Projects	Various	Industrials - Earthing and tap-offs	53k
Non Specific	Customer Driven Projects	Various	Industrials - Transformers	265k
Non Specific	Customer Driven Projects	Various	Subdivisions - Earthing and tap-offs	21k
Non Specific	Customer Driven Projects	Various	Subdivisions - Management	11k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Customer Driven Projects	Various	Subdivisions - Transformers	106k
Non Specific	Line Renewal	Whole Network	11kV Line Renewal Emergent	670k
Non Specific	Line Renewal	Whole Network	33kV Line Renewal Emergent	206k
Non Specific	Line Renewal	Whole Network	LV Line Renewal Emergent	106k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	56k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	11k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	11k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	42k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	34k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	338k
Hangatiki	Line Renewal	Otorohanga	112-04 11kV Line Renewal	98k
Hangatiki	Line Renewal	Mokau	128-04 11kV Line Renewal	94k
Hangatiki	Line Renewal	Oparure	107-02 11kV Line Renewal	109k
Hangatiki	Line Renewal	Mokauiti	115-03 11kV Line Renewal	275k
Hangatiki	Line Renewal	Coast	125-03 11kV Line Renewal	193k
Hangatiki	Line Renewal	Benneydale	103-04 11kV Line Renewal	415k
Hangatiki	Line Renewal	Oparure	107-01 11kV Line Renewal	72k
Hangatiki	Line Renewal	Maihiihi	111-07 11kV Line Renewal	203k
Hangatiki	Line Renewal	Coast	125-03 LV Line Renewal	14k
Hangatiki	Line Renewal	Oparure	107-02 LV Line Renewal	166k
Hangatiki	Regulators	Hangatiki East Feeder	FED102 Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	96k
Hangatiki	Substation and 33 kV Development	Te Waireka Zone Substation	ZSub203 Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1463k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Transformers - Ground Mounted	Waitomo	T1003 Rebuild to regulations and current TLC standards.	45k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T1174 Rebuild to regulations and current TLC standards.	45k
National Park	Line Renewal	Raurimu	410-01 11kV Line Renewal	355k
National Park	Switchgear	Chateau	15N12 Add 11 kV switchgear to transformer.	45k
National Park	Transformers - Ground Mounted	National Park	14L05 Rebuild to regulations and current TLC standards.	45k
Ohakune	Line Renewal	Turoa	415-02 11kV Line Renewal	43k
Ohakune	Line Renewal	Tangiwai	416-04 11kV Line Renewal	149k
Ohakune	Line Renewal	Turoa	415-01 11kV Line Renewal	561k
Ohakune	Transformers - 2 Pole Structures	Turoa	20K09 Ground mount with 100 kVA transformer.	45k
Ongarue	Line Renewal	Ongarue	421-01 11kV Line Renewal	428k
Ongarue	Line Renewal	Ohura	413-06 11kV Line Renewal	182k
Ongarue	Line Renewal	Southern	409-06 11kV Line Renewal	71k
Ongarue	Regulators	Matapuna Feeder	FED404 Install Regulator on Taupo Road to boast voltage for back feeds and customers further down Taupo Road.	96k
Ongarue	Substation and 33 kV Development	Ongarue / Taumarunui Feeder	FED604 Install reactive power capacitors.	103k
Ongarue	Switches	Hakiaha	5.4 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
Ongarue	Switches	Hakiaha	5.3 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
Ongarue	Switches	Hakiaha	5.23 Upgrade SDAF RMU 5-3, 5-23, 5-4 to modern equivalent.	38k
Ongarue	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes, cable unprotected.	45k
Tokaanu	Line Renewal	Rangipo / Hautu	424-03 11kV Line Renewal	126k
Tokaanu	Line Renewal	Hirangi	405-01 11kV Line Renewal	32k
Tokaanu	Line Renewal	Lake Taupo 33	606-01 33kV Line Renewal	72k
Tokaanu	Switches	Rangipo / Hautu Feeder	FED424 Add LV links through town.	113k
Tokaanu	Transformers - Ground Mounted	Tokaanu	10R20 Rebuild to regulations and current TLC standards.	45k
Whakamaru	Line Renewal	Wharepapa	122-05 11kV Line Renewal	253k
Whakamaru	Line Renewal	Tirohanga	129-02 11kV Line Renewal	472k
Whakamaru	Substation and 33 kV Development	Mokai Point of Supply	ZSub3358 Increase capacity taken from Mokai Geothermal.	394k

TABLE 11-1: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2012/13 TO 2026/27 FOR ALL POS (WITHOUT INFLATION)

Section 12

12. Acknowledgements

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The efforts of the TLC Engineering and Asset Management Team, contractors and other staff are also acknowledged in the implementation of this plan to ensure TLC customers receive the best value for money possible with the tools we currently have available within the TLC network assets.

TB Norriss
Engineering Manager
March 2012