EASTLAND
NETWORK LTD

ASSET MANAGEMENT PLAN

1 April 2004 to 31 March 2014

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Submitted in fulfilment of Requirement 24(2) of the Electricity Information Disclosure Requirements 2004 and Amendments

AMP Version 5.0

EXECUTIVE SUMMARY

Purpose and Background

This Asset Management Plan (“AMP”) has been prepared to meet regulatory compliance requirements, demonstrate responsible asset stewardship, integrate customer views, and communicate and justify network management practice and expenditure to Eastland Network (“ENL”) stakeholders. Primary stakeholders include ENL’s shareholders and customers, including retailers, generators and end-use electricity consumers. Other parties with an interest in ENL’s asset management include contractors who physically work on the system and regulatory agencies.

Covering a 10 year period from 2004 to 2014, and prepared on 30 June 2004 the plan documents how ENL ensures long lived network assets are being managed in a sustainable way over their lifecycle. The next revision of the AMP, (covering the period 2005 to 2015) will be prepared for disclosure on 30 June 2005.

Many factors impact on the effective long term management of a complex network of electricity assets, the life of which exceeds the tenure of the Managers responsible for them and whose operating environment introduces significant investment risks. For this reason, the overall scope of the AMP is wide, covering likely changes in the regulatory environment, future service demands and technology development.

While making long term projections to provide sustainability and establish the framework for ENL’s future, the AMP primarily drives work programmes in the short to medium term. It is in all respects a living document. The practices and processes described are subject to continuous improvement, and detailed work programmes are progressively refined throughout the year. The ENL asset management team is the “owner” of this AMP.

The Assets

The distribution network assets included within the scope of the AMP are indicated below together with quantities and the current replacement cost valuation. Note the valuation figures are provisional and based on the draft ODV Handbook December 2003.

	Category	Quantity	Valuation (RC)($000)
1	50/33 kV Overhead lines	327 km	5136
	50/33 kV Poles	2441	10154
	33kV Cables	0.07	11
2	11 kV Overhead lines	2454 km	25326
	11 kV Underground cables	122 km	11172
	11 kV Poles	26856	36436

3	LT Lines	538 km	10223
	LT Cables	188 km	11614
	LT Poles	9455	9408
4	Service connections	24876	5617
5	Load control equipment (Relays) **		
6	Major substations **	19	12504
7	Zone transformers **	23	4628
8	Circuit breakers ***	181	
9	Distribution transformers	3509	18619
	Voltage Regulators	9	585
	Distribution Substations / Switching Stations	3583	5339
10	Pole mounted isolation equipment (11 kV Fuses)	2856	6253
11	Distribution 11 kV switchgear (includes ABS's and branch fusing)	1562	8913
	Sub-transmission Switchgear	14	205
12	LV switchgear *	533	
13	Control and protection equipment ****	-	435
14	Communications equipment ****	-	680
15	SCADA ****	-	341

* LV switchgear values are included with LT cables and Distribution Substations

** Includes Communications, SCADA Control Equipment, Land, Load Control Injection Equipment, Switchgear and Transformers at the sites.

*** Costs are included in major substations and distribution switchgear

**** Costs exclude items in major substations. Control and protection equipment costs include site establishment for remote 50kV switching stations.

Like most network infrastructure, ENLs distribution assets are dispersed over a large area and are highly interdependent. Although the service area includes Gisborne city and Wairoa township, the existing network is predominantly rural in character. It is also the cumulative result of almost 80 years investment and development.

The average age of the distribution network at the end of 2003/04 planning period is estimated to be 22 years. This is expected to remain the steady state by the end of the planning period. However further network renewal will be undertaken to meet improved service targets and growth demands. The condition profile of substation assets and major transformers has benefited from upgrades undertaken over the past 5 years, while other assets such as load control and protection equipment will be the subject of technology driven renewal in coming years.

Corporate Objectives and Strategy

Eastland Network Limited (ENL) is owned by the Eastern Energy Community Trust (EECT) and as such, management has a strong focus on community-based objectives. Delivery of price, services and quality are all factors that influence the competitiveness of local wealth creating business. During the 2003/04 financial year the EECT (the Eastland Network Limited Shareholder), in conjunction with the Board of Eastland Network Limited, signaled its desire for a management company to service the management requirements of the operating companies that the EECT owned. This resulted in Eastland Infrastructure Limited (EIL) being formed and engaged by ENL to provide management and support services. The establishment of EIL has enabled the company to reduce overhead costs.

The introduction of the final Electricity Lines Company Regulation and the Targeted Control Regime, has further enhanced and quantified ENL's focus on price, service and quality. EIL's management strategy for the Network business is to add to its shareholders value whilst ensuring it remains compliant with the new regulatory regime.

Lack of retail competition and inefficiencies in transmission services delivery are major cost drivers for ENL's business. Transpower transmission lines from Tuai to Gisborne are nearing a point where they will not be able to meet a reasonable contingency test. ENL needs to work with Transpower and the regulatory bodies to determine who is best placed to own the assets required to ensure capacity is provided in a cost effective manner.

Looking to the future the company has formed a view that investment in further distributed generation can improve network performance, defer capital expenditure in transmission upgrades and provide local industry with a competitive and sustainable energy source. A number of trial sites have been set up for wind generation and these are achieving positive results. Other initiatives include the investigation of generation opportunities using hydro and coal.

ENL's overall business performance objective is to achieve and maintain an industry position that is above the average of a benchmark group of comparable companies for returns and growth. In addition to establishing appropriate valuation targets for segments of it's network and implementing plans to reduce or increase value accordingly, ENL's pricing policy also serves to signal true economic costs as far as possible and ensure efficient asset allocation and investment decisions. Strategic objectives for adding to organizational competency include a focus on quality, health and safety improvements, risk management processes, staff training and development.

Service Levels

The overall objective of asset management is to ensure the most efficient and optimum investment in assets to provide desired service delivery. Performance targets are established by considering a wide range of business and asset management drivers, some directly influenced by stakeholders, others a result of the historical pattern of development of ENLs network. ENL has surveyed major customers in various market segments and considers their views and willingness to pay when making base investment decisions.

A backlog in network renewal existed at the start of the 2000/01 planning period, which evidenced itself in an aging network and poor reliability performance. Between 2000 and 2004 the majority of the network condition issues have been corrected, providing a network configuration and capacity that is sufficient to meet minimum service targets. With completion of the majority of this work, resulting improvement in reliability statistics, the focus has returned to operational performance.

ENL describes levels of service delivery and efficiency using well recognised and disclosed industry performance measures. The most significant reliability measure is the System Average Interruption Duration Index ("SAIDI"), which indicates network performance in terms of the interruptions experienced by customers.

Key reliability and efficiency performance targets for the next 5 years are indicated:

PERFORMANCE MEASURE	2003/04 Actual	2004/05	2005/06	2006/07	2007/08	2008/09	Average 2004~2008
SAIDI : B Planned	38	45	43	41	39	39	42
SAIDI : C Unplanned	293	255	242	230	219	219	248
DIRECT COST/kM	744	744	743	714	714	714	725
INDIRECT COST/connctn	60	60	60	60	60	60	60

While ultimately it is customer requirements and financial commitments that drive work programmes, after this date it is intended to maintain levels of reliability performance. It should be noted that external influences such as severe storms can dramatically impact upon reliability statistics and year-to-year variances can be large.

ENLs overriding objective in setting service levels is to deliver improved customer value by matching the performance of its assets and all asset activities to the performance customers expect and are willing to pay for. Targets also reflect the requirement on ENL to maintain compliance with Quality Thresholds 6(1) (a) and 6(1) (b), forming part of the Targeted Control Regime for Electricity Lines Businesses. The minimum targets established above reflect average performance within a benchmark group of utilities of similar size, customer density, urban/rural split, and transmission remoteness.

Maintenance expenditure is the dominant component of the disclosed direct cost efficiency measure. ENL has achieved a lower than NZ average spend and this is forecast to continue trending downwards.

Future Demand

ENL has experienced several years of moderate to high base load growth and expects this to continue. However growth is uncertain and is driven by the regions economic outlook, and in the longer term, by changes in technology and other factors.

Growth is particularly sensitive to the pattern of development of the regions forestry resources, gas resources and industry. New technology and the use of distributed generation represent very real opportunities to ENL to reduce the need for transmission and distribution network upgrades.

Facing the challenges associated with serving a consumer base that is very different to what has historically planned for, ENL uses a variety of load forecasting techniques to help predict the impact of accumulated load growth on its capacity requirements and security standards. Coincident system peak demand has been forecast to grow from 57 MW in 2002 to 71 MW in the horizon year, 2014. Predictions use an optimistic/worst case model to ensure timely planning. This base forecast includes foreseeable industrial developments. Specific triggers have been identified for major upgrades to ensure efficient investment to meet security standards and avoid capacity constraints.

Lifecycle Management Plans

Life cycle management plans outline exactly what is planned to manage and operate the assets at the target levels of service while optimising lifecycle costs. An assets life cycle starts with planning its necessity, continuing through design, investment, operation and maintenance, and concluding with replacement and/or disposal. Life cycle asset management encompasses the policies and practices applied during all phases of an assets life to ensure the sustainable delivery of a power supply in the most efficient manner.

ENL uses load flow analysis to assist in identifying solutions to network issues such as security, power quality and uneconomic supplies. Alternative scenarios and options are modelled to optimise development plans, while the timing of work is largely determined by expected load growth.

Detailed life cycle management plans are prepared by asset and expenditure category. Capital plans present background data and plans for renewal, replacement, augmentation and non-asset solutions in response to asset aging, growth, reliability, performance, compliance and quality. Maintenance plans detail the regular on-going work that is necessary to keep assets operating, including the basis for condition monitoring, equipment standards, planned maintenance and provisions for unplanned actions in response to faults or incidents. ENL drives maintenance work based on condition and reliability monitoring, as opposed to planned maintenance based on time usage of an asset.

Since ENLs assets are in the age replacement phase of their life cycle, the management tactic focuses on replacement over heavy maintenance. The expected improvement in average asset condition will lift performance and allow low maintenance expenditure to be sustained.

A review of ENLs achievements against its plan and performance trends confirmed the benefit of the major compliance programme completed in 2001/02.

Asset Management Practices

The asset management process prioritises the programs for maintenance and asset development to ensure optimum customer service and operational efficiency. This includes the recognition of the needs of large customers who are willing to pay to have additional security and/or reliability of supply. Implicit in the asset planning process is an understanding and evaluation of the risks to operation and the consequences of failure. ENL is continually striving to find more efficient ways to carry out its activities, reducing costs and improving productivity.

The systemised processes that form the core of asset management practice and decision making at ENL are condition assessment, reliability performance analysis, asset utilisation/capacity evaluation, risk management, economic optimisation, and benchmarking.

Management services only are provided by EIL to ENL. This includes fulfilling ENL's planning, design and network operating activities. Since all physical work on the network is contracted out, the network operating function includes significant responsibility for contractor management. In addition to applying commercial disciplines to project identification and justification, ENL negotiates competitive contracts for maintenance and capital projects. The need to train and continuously upgrade the skills of internal staff is recognised through improvement programmes and specific training. In the case of contractors and suppliers, forward-looking commercial agreements encourage a partnering approach to skills development and productivity improvement.

Asset Management Systems

ENL uses a variety of information systems to store information on its assets, their condition and performance. Between 2002 and 2004, the compliance programme and associated data capture has driven major improvements in the completeness and quality of asset information. A majority of the asset attribute and maintenance information is stored in databases associated with the GIS system. Stand alone systems provide work management and core financial management capabilities.

The SCADA system provides real time data and enables remote control of key components of the network. This data and network modelling software is used to analyse the network and the impact of changes in utilisation and operation.

The geographical information and modelling system was implemented in 2003. Following completion of the data conversion phase in 2004 the application development phase is continuing to enhance asset information analysis to allow ENL to more effectively improve and optimise network investment and customer service.

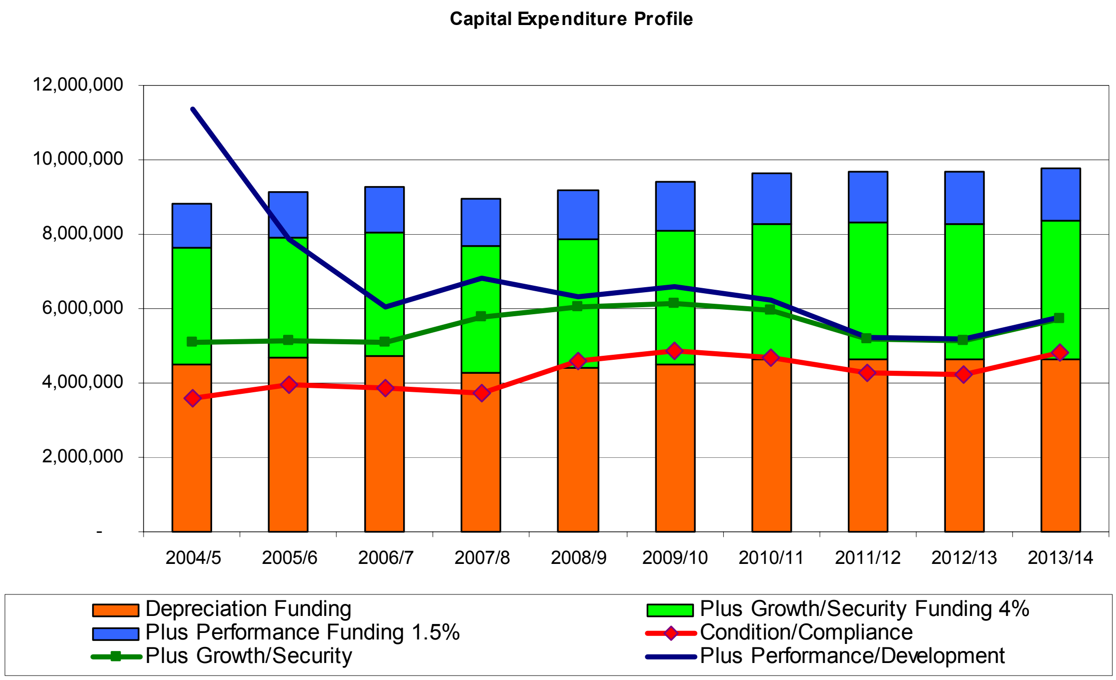
Risk Management

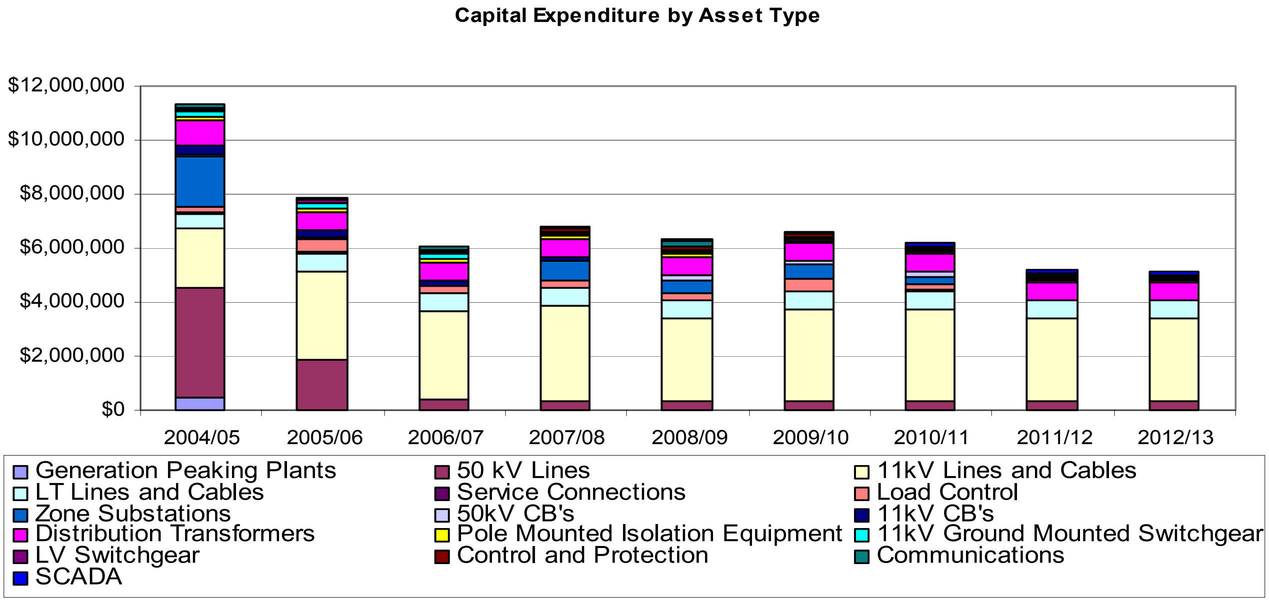
Effective risk management is required to protect the long-term viability of ENL and to protect its stakeholders. ENL uses a systematic outcome-based method for assessing asset related risks. This focuses on identifying and prioritising mitigating actions, which are subsequently captured in work programmes and network development plans. Specific risk issues, contingencies and actions are also identified for each main asset category.

A more comprehensive Risk Management Plan is presently under preparation as part of a full review of EIL's risk management processes. The review and action plans are scheduled for completion in July 2004.

Financial Summary

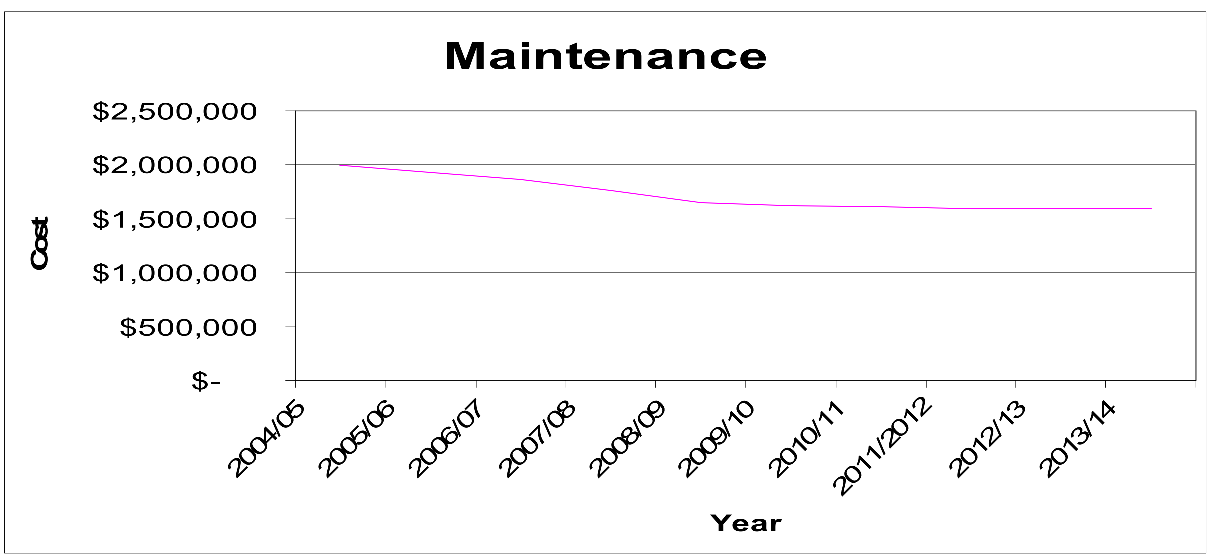
The financial outcome of the management strategies and specific maintenance, renewal and development plans planned by ENL for the next 10 years are summarised below, separating capital and maintenance related expenditure.





Total capital expenditure over the planning period is almost $67.3m and exhibits close to a steady-state profile. Condition and compliance driven capital expenditure is fully funded from depreciation provisions, while growth and security driven capital expenditure provides for customer driven network extension and capacity upgrades. Only major projects where upgrade triggers are already exceeded are included, hence expenditure declines after 2 years.

Performance and technology driven capital expenditure is mainly associated with phasing in of new load control technology over the planning period and improvements in rural protection and automation.



Maintenance expenditure over the planning period is $17.2m, reducing steadily from $1.99m in 2004/05 to $1.59m in 2013/14. This decrease is resultant from investment in improving asset condition and performance and hence predicted reductions in unplanned maintenance expenditure.

Improvement

Improvement is the primary responsibility of the asset management team and is continuous as the AMP is updated during the normal business planning cycle. Internal and external audits are undertaken at regular intervals and are directed at: confirmation of the validity of technical content, assessment of asset management performance against best practice, and identification and implementation of improvements.

ENL is continually reviews the benchmarking of asset management practices in order to more effectively target improvements. Performance measures have been developed to ensure that meaningful comparisons with comparable lines companies can be undertaken and compliance with regulatory targets is maintained.

Ongoing asset management improvement initiatives target the correction of condition and asset data deficiencies and increased detail of asset attributes and performance. The confidence levels ascribed to the actions derived in the AMP will be improved via completion of a more comprehensive risk management plan, more detailed load forecasting information achieved via closer customer liaison, and a major quality programme which will include all asset management activity.

CONTENTS

1. INTRODUCTION

1.1 Terms of Reference

The Electricity Information Disclosure Requirements 2004 ("EIDR") require Eastland Network Limited ("ENL") to update and disclose an Asset Management Plan ("AMP") in June each year. ENL has progressively updated and developed the AMP since preparation of the first formal consolidated document in March 2000. This fifth issue is intended to not only meet regulatory compliance requirements but also to serve as the main stay of network management and planning. The AMP demonstrates responsible asset stewardship and communicates and justifies funding requirements.

In the context of infrastructure asset management, this AMP is in an early stage of development. In the short term, there are constraints on the availability and quality of data and elements of the AMP have to be annually updated and corrected so that predictions track actual performance. Longer term there is a need to realign the AMP with wider changes in the economic and business environment, advances in technology, and amendments to company objectives.

The AMP is in all aspects a living document. While making long term projections to prove sustainability and establish the framework for ENL's future, the AMP primarily drives work programs in the short to medium term where models and predictions are more accurate.

1.2 Reconciliation with Disclosure Requirements

Requirement 24 of the EIDR requires every line owner other than Transpower to disclose an AMP in relation to their works, and Schedule 2 mandates information requirements. Although prepared to comply with the requirements of the regulations, in some instances the section titles and the location of information in this AMP differs from Schedule 2 for editorial reasons. Table 1.1 reconciles the content of this AMP to the mandatory disclosure requirements.

1.3 Planning Period

The AMP is intended to demonstrate that assets are being managed in a sustainable way over their life cycle. The life cycle of assets varies between 15 and 60 years but is typically in the order of 40 years. The average long run age of the asset base once it has matured to steady state is therefore 20 years. This AMP projects asset replacement programs for a 10 year planning period. The planning period used is consistent with the 10 year planning horizon used in the conduct of long term financial and strategic planning at ENL.

Table 1.1 : Reconciliation to the Electricity Information Disclosure Requirements 2004 and Amendments

Section	Comments	EIDR 2004 – Schedule 2
		Asset management plans must include the following information:
ES	The Executive Summary has been included to aid understanding and readability of the AMP by those who do not require the detailed information presented in the body of the document.	(a) Summary of the asset management plan— (i) Purpose of the plan: (ii) Date the plan was completed and the period to which the plan relates: (iii) Asset management systems and information: (iv) Network and asset description: (v) Service level objectives: (vi) Lifecycle asset management and development plans: (vii) Risk assessment: (viii) Performance and plans for improvement.
1.0	Introduction to the AMP.	(b) Details of asset management plan background and objectives, including—
2.0	Interaction with corporate goals is described generally in Section 2.0. The overall planning framework is set out in Section 3.0. The planning processes and links to other documents are described in Section 3.3. Discussion of strategic corporate goals and issues is provided in Section 4.2.	(i) Interaction with other corporate goals, business planning processes, and other plans:
1.3	Provided in the introductory Section 1.3 with a planning timetable in Section 1.4	(ii) Planning periods adopted:
3.1	Stakeholders are identified within the planning framework in Section 3.1, while discussion of their interests and impact on target levels of service is set out throughout Section 4.0	(iii) Stakeholder interests (owners, consumers, etc):
1.0	The ENL organizational structure and asset management responsibilities is provided in	(iv) Accountabilities and responsibilities for asset management:

Table 1.1 : Reconciliation to the Electricity Information Disclosure Requirements 2004 and Amendments

Section	Comments	EIDR 2004 – Schedule 2
	Section 1.5	
3.4	Asset management systems	(v) Details of asset management systems and processes including asset management information systems/software and information flows.
3.3	Asset management processes and information Flows	
8.0A	Comprehensive details by asset category together with information on network architecture are presented in the lifecycle management plans to prevent duplication.	(c) Details of assets covered, including— (i) Description of the asset configuration: (ii) Identification of assets by category: (iii) Justification for asset: (iv) Location, age, and condition.
4.0 4.3.1- 4.3.4 4.3.5	Current and target levels of service.	(d) Details of proposed levels of service, including— (i) Consumer oriented reliability, security, and availability performance targets: (ii) Other targets relating to asset performance, asset efficiency, and effectiveness and efficiency of line company activity:
4.0	Detailed discussion of targets and drivers is provided in Sections 4.1-4.3 while comparative benchmarking is discussed in Section 4.4	(iii) Justification for target levels of service based on consumer, legislative, regulatory, shareholder, and other requirements.
5.0 6.0,8.0	The largest part of this AMP, these provisions are met in Sections 5.0, 6.0 and 8.0A and 8.0B	(e) Details of network development and lifecycle asset management plans, including—
6.1-6.5 8.0A	Network development planning criteria and assumptions are described in Section 6.1-6.5. Asset specific details are provided in Section 8.0A.	(i) Description of planning criteria and assumptions:
8.0B	Maintenance planning criteria and assumptions are described in detail for each asset category in 8.0B	
5.0	Future demand is discussed in Section 5.0.	(ii) Details of demand forecasts, network configuration analysis, reliability assessments, and the specific network locations where constraints are expected:
4.3.1	Information on network configuration	

Table 1.1 : Reconciliation to the Electricity Information Disclosure Requirements 2004 and Amendments

Section	Comments	EIDR 2004 – Schedule 2
6.6 8.0A	analysis, reliability assessments and constraints are provided in Sections 4.3.1, 6.6 and 8.0A. Constraints are specifically discussed in each asset category of 8.0A and in Appendix 11.2	
8.0A	Non-asset solutions are specifically discussed under each category in 8.0A Distributed generation is discussed in terms of corporate objectives and impacts on demand in Sections 4.1.1 and 5.0. The network investment policy for generation, transmission, distribution and load based investments is in Appendix 11.4	(iii) Policies on non-asset solutions, distributed generation, redeployment and upgrade of existing assets, acquisition of new assets, adoption of new technology, and disposal of existing assets:
8.0A	Justification for detailed work programs and scheduled actions to meet service targets is presented by asset category in 8.0A.	(iv) Analysis of the options available and details of the decisions made to satisfy and meet target levels of service:
8.0B 9.1.2	Maintenance activities are described in detail by asset category in Section 8.0B. Summarised expenditure projections are provided in Section 9.1.2	(v) Description and identification of maintenance policies, programmes and actions to be taken for each asset group, including associated expenditure projections:
6.6 8.0A 9.1.1	The network development plan is summarised in Section 6.6, and specific actions by asset class set out in Section 8.0A. Summaries of capital expenditure are provided in Section 9.1.1.	(vi) Description and identification of the network development programme (including distributed generation) and actions to be taken, including associated expenditure projections.
7.0	Section 7.0 provides an overview of risk management at ENL.	(f) Details of risk policies, assessment, and mitigation, including—
6.2	Network related risks and ranking are provided in Section 6.2.	(i) Methods, details, and conclusions of risk analysis:
7.0, 8.0	Discussed in Section 7.0 and for each asset category in 8.0	(ii) Details of emergency response and contingency plans.
10.0	AMP improvement and monitoring is discussed in Section 10.0.	(g) Details of performance measurement, evaluation, and improvement, including—

Table 1.1 : Reconciliation to the Electricity Information Disclosure Requirements 2004 and Amendments

Section	Comments	EIDR 2004 – Schedule 2
4.5	Service level performance history is provided in Section 4.4.	(i) Review of progress against plan, both physical and financial: (ii) Evaluation and comparison of actual performance against targeted performance objectives:
10.0	Major AM improvement initiatives are described in Section 10.0	(iii) Gap analysis and identification of improvement initiatives.

1.4 Planning Timetable

The annual planning cycle is driven by the disclosure regime and the 31 March financial year.

April	-	Statement of Corporate Intent
May	-	Annual Report
June	-	ODV
Jul	-	Disclosure
Aug	-	Gazette
Sept	-	Analysis and Benchmarking
Oct	-	½ Year Report
Nov	-	Strategic Planning
Dec	-	Operations Review, Contract Review, Pricing Review
Jan	-	Budgeting, Asset Management Plan review
Feb	-	Business Plan
Mar	-	Work Programs

Several months are required for some of these activities so most processes are running in parallel with others.

1.5 Organisational Structure

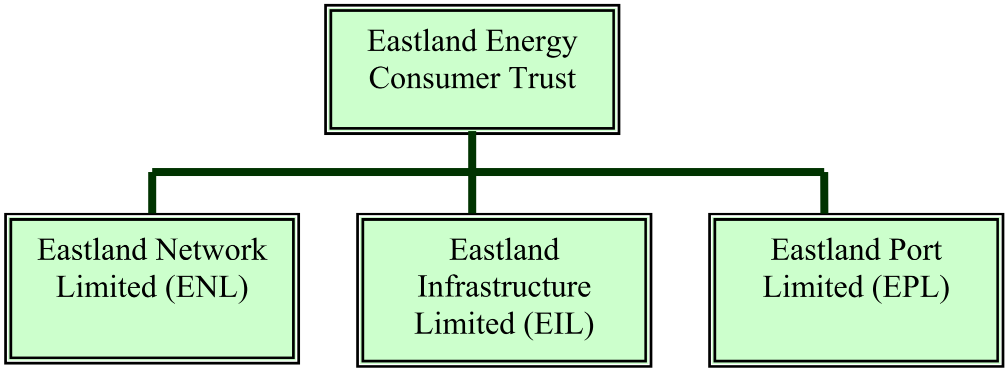
EIL is a management only company, which provides management and support services to both ENL and Eastland Port Limited (EPL). EIL, ENL and EPL are all wholly owned by the Eastland Energy Consumer Trust (EECT). Specifically for ENL, EIL provides management services in support of its planning, design and network operating activities. Since all physical work on the network is contracted out, the network operating function includes significant responsibility for contractor management.

The Operations Division of the company has a structure reflects a separation between long term planning activities and short term operations. The Planning Group undertakes asset planning and design work and incorporates the company's professional engineering resources and the drawing/information record keeping. Production of the AMP is a key accountability of the Asset and Planning Manager.

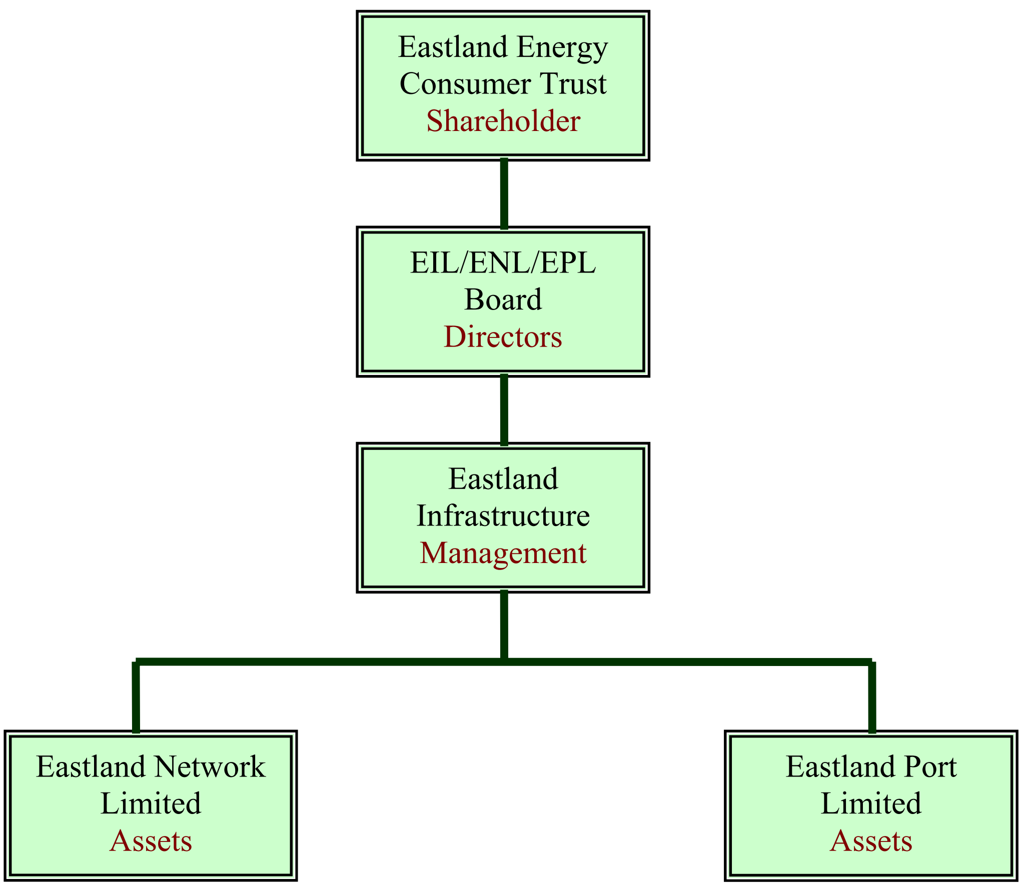
The Operations Group implements work programs, operates the network, and manages contractors. Delivery of reliability and cost performance are the key accountabilities of this group. Contract and operation reviews provide additional feedback from contractors.

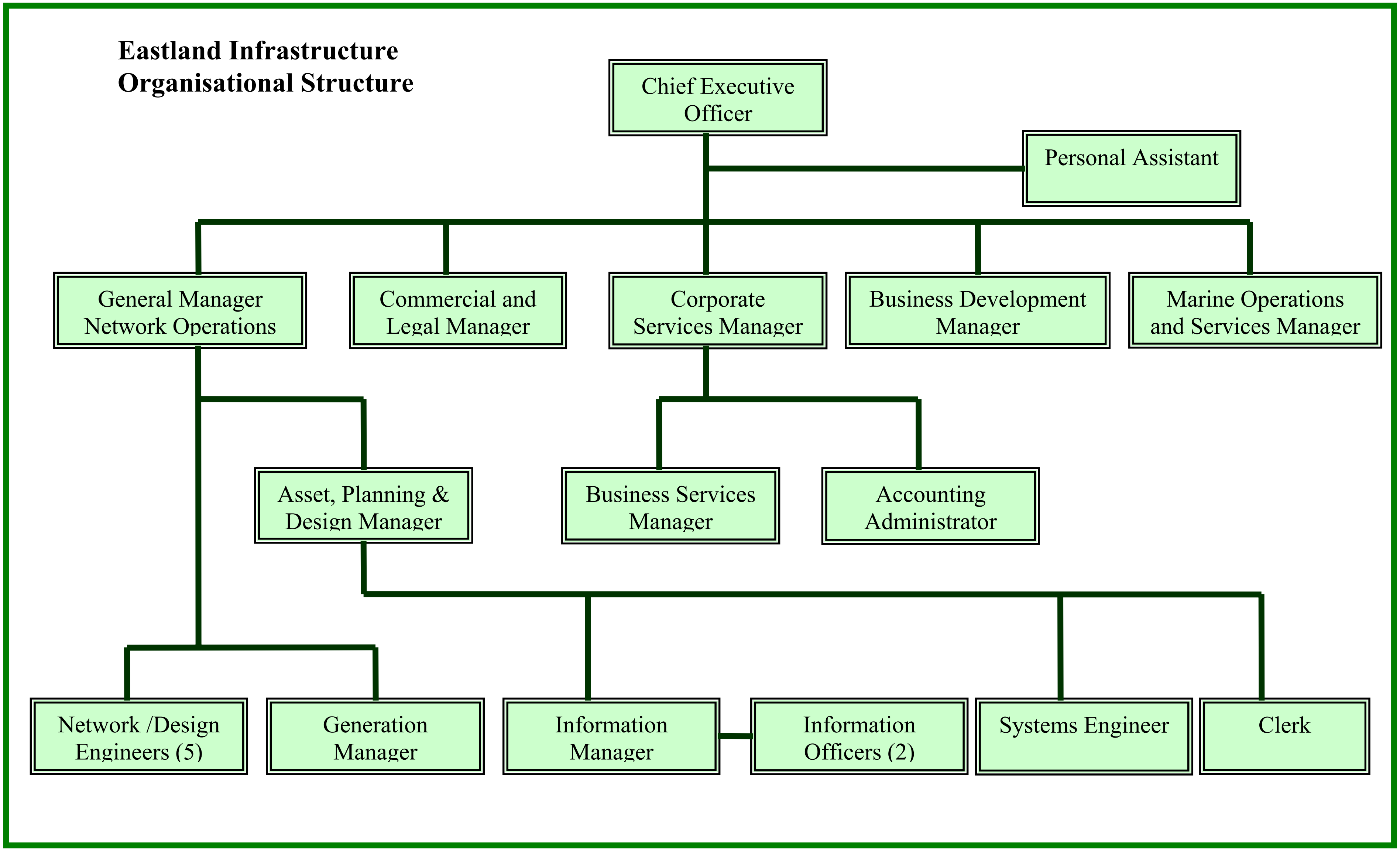
Close interaction between Planning and Operations is achieved through the stewardship of the GM Operations, who has overall accountability for the performance of ENL assets. Shared Control Room duties also fosters close interaction between Planning and Operations.

Ownership Structure



Governance / Management




Eastland Infrastructure
Organisational Structure
Chief Executive Officer
Personal Assistant
General Manager Network Operations
Commercial and Legal Manager
Corporate Services Manager
Business Development Manager
Marine Operations and Services Manager
Asset, Planning & Design Manager
Business Services Manager
Accounting Administrator
Network /Design Engineers (5)
Generation Manager
Information Manager
Information Officers (2)
Systems Engineer
Clerk

2.0 CORPORATE GOALS

2.1 Asset Management Objectives

The Objective of Asset Management is to create the optimum investment in assets to provide:

1) Desired service delivery
2) In the most cost efficient and effective manner

Distribution network assets are very long term investments made in an environment, which has relatively short cycles of change. Over the life of the investment the status quo is challenged by technology changes, increased service demands and changing usage. This operating environment introduces significant investment risk, which has to be minimised through good management. The life of assets also exceeds the tenure of the Managers managing them. Therefore the AMP is an important map for future decisions and a record of past decisions.

Those decisions include:

- What assets should we invest in and what value is sustainable?
- How should assets be maintained, operated and managed?
- When should assets be replaced?

The performance of a network is measured by the "cost - service" trade-off and includes the wishes of specific larger customers, which might differ from what might normally be provided and subject to their willingness to pay. The disclosure regulations controlling monopoly networks provide measures that can be used to benchmark performance. Reliability statistics are used as the performance measure for service. Other service issues such as quality and security are set as standards determined by industry practice. Cost efficiency is measured directly by comparing operating, maintenance, and administration costs normalised for network size.

Optimum investment decisions will deliver the best value. Investment in assets that do not meet shareholders requirements for returns, result in a write down of economic value. This situation can be reduced by:

- Providing a more efficient design that lowers the level of investment needed
- Reducing operating costs through application of technology and work practices
- Reducing service levels
- Increasing prices

Limits of acceptability on these options dictate a balanced application of all four. While network companies are often viewed as monopolies, the extraction of monopoly rents increases the risk of shareholders being stranded with poorly performing assets, as users find cheaper alternatives or relocate to more competitive regions. A network company's survival is linked to the survival of its users. This is particularly true in a provincial economy such as the East Coast.

2.2 Statement of Purpose and Vision

Since ENL is owned by a community trust, management has a strong focus on community-based objectives. The 1998 industry reforms reduced network customers from the traditional consumer base to energy retailers. This isolates networks from retail pricing and service delivery. In ENL's case however, changes to objectives have been subtle because there is a large overlap between consumers and community. ENL's statement of purpose and vision communicate a strong focus on the development of the local economy.

STATEMENT OF PURPOSE

Eastland Network will utilise existing assets to achieve an appropriate return for the shareholder while providing opportunities for business growth and improving the value delivered to customers.

VISION

Eastland Network by 2006 will provide returns on assets, growth on investments and operating performance as an electricity network company, which places it in an average position relative to other New Zealand electricity companies.

Delivery of price, services, and quality are all factors that influence the competitiveness of local wealth creating business. Growth of the economy will provide growth to ENL.

2.3 Environmental Management Policy

ENL is committed to managing and operating its business in a manner which meets the community's environmental expectations while meeting obligations to provide reliable, safe and economic network services.

We strive to meet a prudent balance between the community's need for electricity and that of effective environmental management.

ENVIRONMENTAL MANAGEMENT POLICY

In planning and undertaking activities, which have implications for the environment, Eastland Network will adhere to the following principles:

High standards of environmental management and staff awareness will be maintained

Environmental considerations will be a priority in planning new business activities

The active promotion of end-use network efficiency and conservation will be an integral part of our business strategy

All legal requirements relating to environmental management, including laws, regulations and resource consent conditions, will be complied with

3.0 THE PLANNING FRAMEWORK

ENL's asset management process is illustrated in Figure 3.1. Stakeholders directly influence and determine asset management drivers at ENL. These drivers are taken into account in the formulation of ENL's strategic plans. The asset management process serves to convert strategy, as it applies to the physical network assets, into action. Detailed consideration is given to management, financial, economic and engineering issues to ensure the required levels of service are provided in the most cost effective manner. The extent to which this primary goal is achieved is continually assessed, completing the performance feedback loop.

The main elements of this framework are described in the following sections.

3.1 Stakeholders and Influences

- Shareholders
  ENL is owned by the Eastland Energy Community Trust ("EECT"). Trustees are appointed by the Gisborne District Council, the EECT's capital beneficiaries, to represent the interests of the community income beneficiaries. The EECT is responsible for appointing the Board of Directors and agreeing the Statement of Corporate Intent. Eastland Infrastructure Limited is the management company formed by the EECT and engaged by ENL to provide management and support services to it.

- Customers
  ENL manages the network to meet the needs of all residential, commercial and industrial electricity consumers in the region. It focuses on the wealth-creating sector of the local economy. ENL also consults with major customers to determine their preferences regarding security and reliability of supply.

- Regulations
  Statutory requirements impact on how ENL operates to meet its service targets. In addition to meeting the requirements of health and safety and resource management legislation, ENL is a regulated monopoly business that is subject to controls and an information disclosure regime, in particular the commencement of the Electricity Lines Company Regulation and the Targeted Control Regime. Changes to this regulatory environment will occur over the period covered by this plan.

3.2 Asset Management Drivers

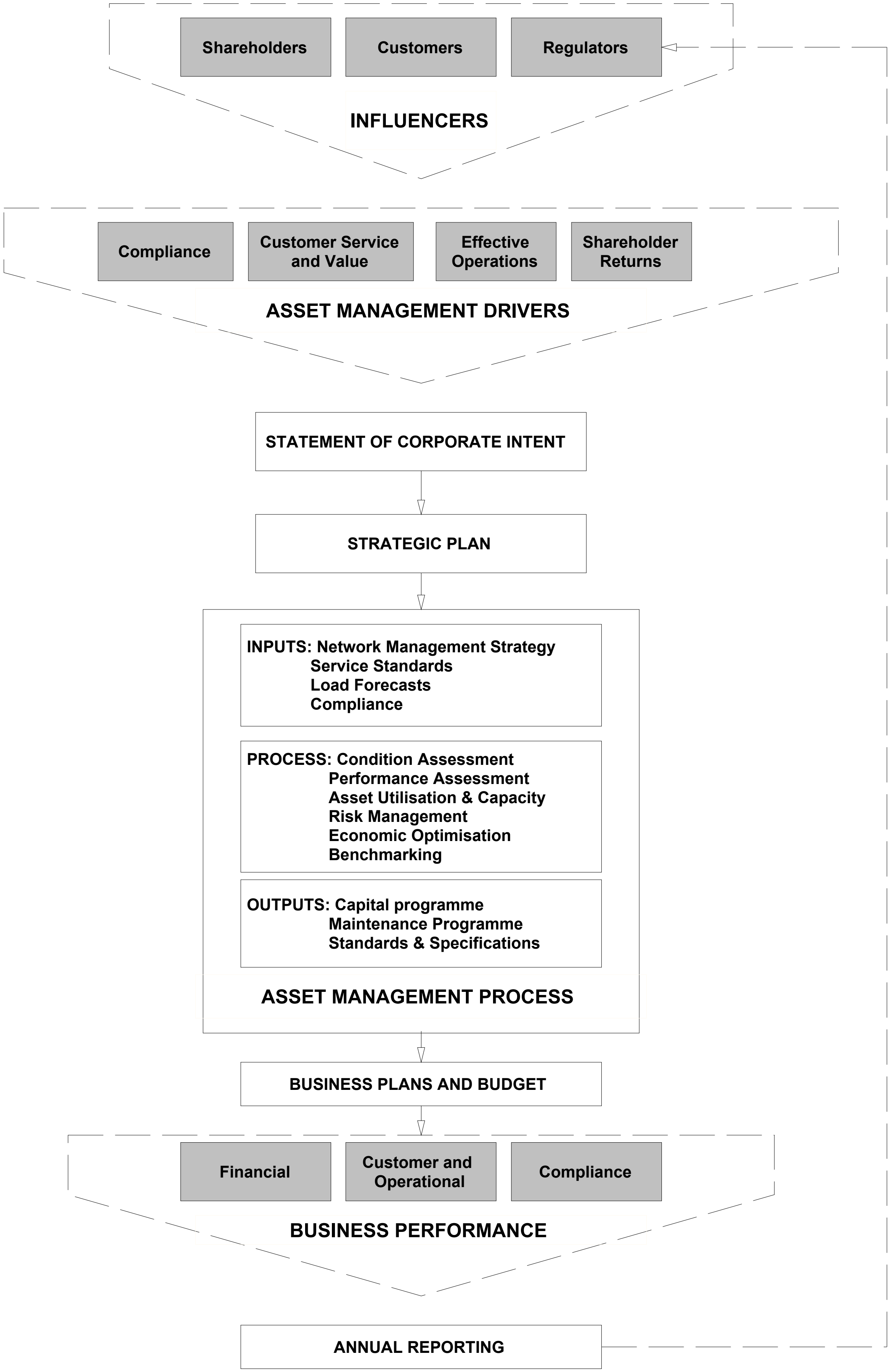
- Customer Service and Value
  ENL's objective is to deliver improved customer value by matching the performance of it's assets and all asset activities, including those of contractors, to the performance customers expect and are willing to pay for. ENL has targeted average performance.

- Effective Operations
  ENL's objective is to manage the operation of its assets in such a way as to deliver the required performance at the lowest overall cost.

- Compliance
  ENL will manage its assets to ensure the safety of its employees, contractors and customers at all times. ENL also will manage the network and act in an environmentally responsible manner and comply with all legal environmental requirements.

- Shareholder Returns
  ENL's objective is to manage its assets to meet the shareholders requirements for return on investment.

Figure 3.1 - The ENL Asset Management Framework



3.3 Asset Management Process

3.3.1 Links to Other Plans and Documents

The AMP is specific to the network and is directly influenced by a number of other policy documents:

- Statement of Corporate Intent
  This document defines the Director's intentions and objectives for ENL for the financial year and is agreed with the shareholders. This encompasses planned business activities and objectives, values, performance targets and communication methods.

- Strategic and Business Plans
  Annual plans and key initiatives are established to support the achievement of performance targets. As the AMP is a tactical plan and repository for detailed asset information, these documents are closely coordinated during the business planning cycle.

- 10 Year Financial Plan
  The 10 Year Financial Plan identifies funding requirements and demonstrates that business performance and service objectives can be met.

- Customer Relationship Management Plans
  These plans developed in 2004 document consultations held individually with major customers regarding their current and future electricity supply requirements and describes their preferences for cost quality trade-offs

The outputs from the asset management process are the operational, maintenance and capital work programmes:

- Maintenance Plans
  Detailed maintenance standards and specific maintenance programs are recorded in the maintenance section of the lifecycle management plans presented later in this AMP (Section 8.0B)

- Development Plans
  Analysis is undertaken to test growth and performance against service standards. A Network Development plan is then created in line with investment and risk policies. This is summarised in Section 6.0 of this plan with other specific capital plans set out by asset category in Section 8.0A of the lifecycle management plans.

- Equipment and Design Standards
  Detailed equipment and design specifications, based on the required functionality of the assets, are included in the Network Quality System. General standards and issues concerning quality and compliance are covering in the lifecycle management sections of this AMP.

Both regulatory change and an ageing asset population require compliance issues to be carefully scrutinised.

3.3.2 Decision Making Processes

The asset management process prioritises the programs for maintenance and asset development to ensure optimum customer service and operational efficiency. Implicit in the asset planning process is an understanding and evaluation of the risks to operation and the consequences of failure. Also critical is the collection of information from which performance can be monitored and improvement targets set. From this document interested parties will be able to identify ENL's performance targets, areas of business focus, forecast levels of capital investment, and their rationale.

The systemised processes that make up the core of asset management practices are those that collect and analyse data. The main processes are:

- Condition Assessment
  Every asset has a condition assessment action included in its maintenance program. This is used to confirm the necessity of further maintenance, target maintenance expenditure and provide ageing data.

- Performance
  Analysis of reliability statistics provides information on the performance of assets, the effectiveness of work practices, and can help target work programmes.

- Asset Utilisation and Capacity
  Load growth and changing profiles are obvious inputs into planning. However security risk and quality issues also require adjustment when load use patterns change.

- Risk Management
  Network related risks are identified and ranked by risk reduction outcomes to help prioritise work programmes.

- Economic Optimisation
  The value of a network results from the asset management practices applied. Economic analysis can indicate whether valuation changes and lifecycle costs are in line with long-term sustainable objectives and therefore which tactics are appropriate for different network segments. Economic analysis is also applied to optimise the balance between capital and maintenance decisions across the life cycle of the network assets

- Benchmarking
  Analysis of disclosure information and industry benchmarks identifies the practices that are most effective and the performance levels that can be achieved given inherent network characteristics.

3.4 Asset Management Systems

ENL uses the following information systems to store information on its assets, their condition and performance.

- Works Database
  The Works Database provides job cost functionality and is used to manage faults, maintenance and work management activities. This is essentially a contract management and cost reporting tool. It provides information on progress, commitments, forecasts and cash flow.

- Financials
  The company uses ACCPAC as its main financial management IT-platform. This is supplemented with Dbit to maintain the financial asset register, which is separate to the engineering asset database.

  The Works Database is reconciled with ACCPAC during monthly reporting.

- Network Control
  The SCADA system provides real time data and enables remote control of key components of the network.

- Network Modelling
  ENL uses PSS/U (Power System Simulation/Utilisation) network modelling software to analyse the network and the impact of changes in utilisation and operation. The software is sufficiently sophisticated to permit advanced network optimisation and analysis and assist investment decision-making.
  Visim is used as the main structural engineering tool for line design.

- Asset Information Systems
  The Powerview Geographical Information system is used for management of asset information, maintenance and inspection records.

4.0 LEVELS OF SERVICE

4.1 Strategic Goals and Issues

Key strategic focus areas and strategies that are relevant to the current planning period are summarised below.

Strategic Focus Area/Objective	Strategies
1. Least Cost Supply Exploit new value-adding business opportunities and reduce total cost of energy supply	a. Develop generation opportunities b. Minimise transmission costs c. Minimise cross-subsidies
2. Network Operational Performance Maintain average operational performance.	a. Targeted reliability improvement b. Reduced OPEX c. Ensure compliance is maintained d. Growth & security provision standards
3. Business Performance Maintain an average position for value growth and financial returns	a. Stabilise value and returns b. Extract revenue protection benefits c. Improve viability of remote supply economics
4. Organisational Capability Build a platform for growth	a. Maintain high safety standards b. Implement quality management c. Maintain staff competencies and skill levels.

These organisational strategies directly address the major issues and opportunities facing ENL and have a fundamental impact on asset management practice and policy. The following sections discuss and put these strategies in context.

4.1.1 Least Cost Supply

Lack of retail competition and inefficiencies in transmission services delivery are major cost drivers for ENLs business. Existing constraints suggest there are opportunities associated with further diversification into generation and transmission, subject to economic assessment and justification. These have the potential to significantly reduce the total cost of energy supply to the East Coast.

Allocative efficiency can be improved by reducing the level of cross-subsidisation that exists between load groups. ENL's pricing policy serves to signal true economic costs as far as possible and ensure efficient asset allocation and investment decisions.

Generation Opportunities

There are a range of generation opportunities on the East Coast that will become increasingly viable as their economics improves. Despite legislative constraints on the extent to which ENL can invest in generation, it is probable that such projects will provide a lower risk and higher return alternative to transmission and distribution upgrades within the 10-year planning period. Strategically ENL will seek the most economic outcome. A number of trial sites have been set up for monitoring potential wind generation opportunities. They are achieving positive results. Other initiatives include the investigation of Hydro and Coal generation opportunities.

Transmission Efficiency

Transmission costs can be directly controlled through effective management of generation and load control. All possible actions are taken to ensure Transpower continually provides economically efficient transmission services.

Network Pricing and Reduced Subsidies

Pricing has a role to play in asset management because it can be used to signal desired load characteristics. The characteristics of the connected load influence asset provision, costs and economics.

The local economy needs to be competitive with neighbouring regions if growth in the wealth of the region is to be achieved. ENL has a strategy of competitive pricing for wealth creators in the region and will ensure cross-subsidisation between load groups in the network is controlled to acceptable limits. The allocation of costs and revenue streams between ENL's load groups is part of a separate pricing methodology disclosure made for our pricing schedule effective 1 May 2004. This continues to adjust the level of cross-subsidisation and allow for Transpower increases while maintaining regulatory compliance with Targeted Control Regime Pricing Thresholds.

Other outcomes that the pricing policy promotes are as follows:

- A Flat Load Profile: a less peaky load profile results in better capacity utilisation. Asset costs are largely proportional to capacity so a fixed charge related to capacity automatically rewards efficient utilisation. Peaks can also be controlled through effective demand side management. On ENL's network the large peak in daily profile is created by domestic load. However it should be noted that any signals only reach the consumer if passed through by energy retailers.

- Single Phase Domestic Connection: approximately 66% less connection equipment is needed to provide a single-phase supply compared to a three phase supply. Small loads such as domestic installations do not require three-phase power and are rewarded with an appropriate differential in pricing. This gives an incentive for single phase conversion of rural network spurs where 3 phase supply replacements cannot be economically justified.

- Maintenance of Power Factor: Gisborne has voltage constraints on its transmission supply. Poor power factor is penalised through higher capacity charges reflecting higher usage.

- High/Medium/Low Density Differential: Differential pricing based on customer density is necessary to signal the widely varying levels of investment per connection on the network. This is currently achieved via a simple urban/rural/remote split but is constrained by the Governments 10 % fixed charge regulation for domestic consumers.

- Variable Component: A variable component is maintained in order for ENL to achieve revenue growth with load growth in order to fund new capacity and associated security. Variable pricing also provides a mechanism for returns for investments in energy efficiency. Variable pricing is achieved through ICP billing using data provided by energy retailers.

ENL's current pricing policy is provided in Appendix 11.7.

4.1.2 Network Operational Performance

ENL has concentrated on addressing network condition issues and providing a network configuration and capacity that is sufficient to meet its service levels objectives. With completion of the majority of this work, the focus has returned to operational performance.

Targeted Reliability Improvement

Continued design and configuration improvements will further enhance system reliability, while use of live line techniques and new technology are expected to maintain service levels within customer expectations and regulatory controls.

Reliability performance improvement projects are justified and prioritised on the basis of operational savings.

Operational Efficiency Initiatives

Maintenance expenditure is the dominant component of the disclosed direct cost efficiency measure. ENL has achieved a lower than NZ average maintenance spend and this is forecast to continue trending downwards towards long term targets.

Tactics that have been successfully applied in the past will continue to be used. These include a reliability based approach to maintenance that focuses on service level outcomes, automation, and protection coordination.

Compliance

In order to minimise risk, compliance related work continues to be a priority and provides improvements in average asset condition resulting in minimal faults and optimum overall reliability. The backlog in network renewal that existed at the start of the 2001 planning period has now been eliminated and compliance expenditure has been reduced to near steady-state levels. Provisions for compliance expenditure in the financial plan are within depreciation provisions over the next 10 years.

Compliance programmes are reflected in the lifecycle management plans set out for each asset category in Section 8.0.

Growth & Security Provision Standards

The detailed provisions of the ENL security policy are set out in Section 4.4. Planning criteria for investment in major upgrades is set out in Section 6.0 and Appendix 11.2. The latter serves to drive efficient investment to meet security standards.

4.1.3 Business Performance

ENL’s overall business performance objective is to provide appropriate shareholder returns while providing opportunities for business growth and improving the value delivered to customers. In addition to establishing appropriate valuation targets for the different segments of it’s network and implementing plans to reduce or increase network value accordingly, ENL continually targets revenue protection and uneconomic supply issues.

Stabilised Value and Returns

One objective of asset management is to optimise the level of investment and mix of assets employed to deliver the required service. The current Optimised Deprival Valuation (“ODV”) of the network provides a useful "peg in the ground" for monitoring the effect of strategies employed to alter the asset mix. Careful analysis can give an indication of the type of changes required and consequently the management tactics that should be applied.

The existing mix of assets is largely the result of historical objectives that are inappropriate for today's environment. As the valuation is a product of asset management and the current valuation is also a driver for change, ENL has given careful consideration to the optimum valuation for it’s network based on corporate objectives and stakeholder requirements.

For a network owned by the community that it serves, a value that maximises the region's ability to create wealth would seem to be an appropriate target. Regional infrastructure costs are generally minimized when assets that have aged to the point where maintenance becomes more costly than replacement are replaced, levering off technical advances or design innovation to maximize future economies.

In situations where an asset is not producing a return that covers its economic cost, alternatives should be sought. In particular, in areas of uneconomic supply, it would seem hard to justify a capital investment where the physical life of the asset is 40 years but the pay back period is 150 years. Most such uneconomic supply areas in New Zealand are the result of past regional development subsidies and are rural in nature.

With the removal of support for subsidies and the present emphasis on economic management of networks, considerable effort has been applied to new and innovative ways to obtain cost effective extension of life. ENL is aware of these developments and is keeping a watching brief on them for possible future application.

For any given region, there is likely to be a particular value for the network ODV that will maximise the region's ability to create wealth. This is unlikely to be either the highest or lowest achievable ODV. ENL has a mixture of very uneconomic to very economic segments in its network; hence each segment is subjected to an individual assessment of the most appropriate value and level of investment.

Calculation of Economic Targets

There are three variables that affect the economics of assets provided for power supply.

- Capacity - the level of utility or service provided by assets. This is a driver for the initial cost of installation.
- Operating Costs - these change during the life of an asset and ultimately give an economic limit on the service life of the asset.
- Return on Assets - Investments must provide a return to the shareholder. For a low risk monopoly business the minimum acceptable return is equal to the cost of capital used to invest in the assets generating income on a sustainable basis. Shareholders may demand an additional premium.

Increasing capacity and operating costs results in a decrease in return on assets if pricing is fixed. Pricing is constrained by factors such as acceptability in the market, the regulatory environment and wider company objectives regarding its infrastructural role in the local economy.

Therefore a trade-off condition exists between asset investment, the cost of operating them and the return on assets.

The economic characteristics of ENL’s disparate service areas vary according to:

- Existing levels of asset investment
- Asset condition
- Customer / load density
- Pricing, Specifically compliance with the price path thresholds.

The following analysis assumes network segmentation based on Eastland Network Ltd's 2002 ODV.

To replace ENL’s network assets with their modern equivalents would cost $183M. The point where assets are, on average, half way through their economic life can be considered steady state, and would indicate an ODRC value of $92M for the ENL network.

The question is whether or not this figure is optimum. The ideal asset mix will change constantly with change in technology, demand, and service requirements. However, physical

asset investment will not match service requirements because of the discrete, discontinuous nature of investment in capacity.
ENL's 2000 ODV was $53M, indicating under investment which was reflected in reliability and service performance. Run down assets and disproportionate increases in urban and industrial loads resulted in an asset mix that was no longer capable of optimum performance. Since then, ENL has largely completed a capital upgrade program equivalent to approximately 40 % of its ODV.

ENL's 2002 ODRC is $67M, indicating that a steady state network asset value had almost been attained. Economic value, however, was lower without increasing tariffs, indicating that the asset mix was not optimum. Sensitivity analysis on ENL's valuation indicated that:

- Rural network segment value is sensitive to increased prices, costs (especially Transmission), and capital expenditure. If ODRC is reduced, return on assets increases, and therefore economic value improves.

- Urban network segments have a high hidden economic value. These segments can sustain high return on investment and there is no reason for constraint on delivering the service levels demanded by users.

Valuation targets for each network segment have been updated based on the 2002 valuation and are presented in Appendix 11.5.

ENL's 2004 ODRC is expected to be around $84M and cannot be confirmed until release of the finalised ODV handbook scheduled for late 2004.

Optimum investment can be achieved by targeting an increase in value in economic segments and reducing value in uneconomic segments. Increasing the portion of assets in economic segments releases economic value at a greater rate than expenditure on physical value.

This strategy is consistent with:

- The need to address increasing urban load and decreasing rural load affecting economics and quality of supply demands.

- Addressing the increasing component of industrial to domestic load requiring different service and security standards.

- Mitigating increasing capacity constraint in urban segments.

- Reducing under utilised assets in rural segments.

- Improving under investment in key areas reflected in asset condition below optimum.

__Tactics for Decreasing Value__

Decreases in value are desired for rural segments supplying remote areas. The annual depreciation on the Replacement Cost of the assets in these areas is approximately $1.8m per annum. By ensuring capital expenditure in these areas does not exceed $1.5m per annum a net decrease of $300,000 per annum is achieved. The decrease required can be achieved within 10 years by this approach.

Renewal programs are focused on zone substations and switching equipment. Exploiting technology and work practices, innovations are allowing renewal to progress at a lower cost than previous investment levels.

The standard 3-phase construction applied in remote areas is no longer appropriate for the expected continuing trend of decreasing load. Automation and 1-phase construction offers a more cost effective design and is discussed further in Section 6.5.2.

__Tactics for Increasing Value__

Load growth and changing load demographics is driving sub transmission and 11kV tie feeder investment. As this has an urban orientation this forced investment will fortunately deliver the desired value increases.

Technology and automation has proven to deliver on increased service demands and to reduce operating costs. This is a shift to best practice.

Increasing urban load is driving some asset (particularly LV network) to its design limits and the need for capacity upgrade will outstrip age replacement. The size of conductor required will dictate underground cable network in order to meet the requirements of design practicability, reliability and customer expectations.

These tactics all achieve value increase from actions that are necessity driven and can be defended against accusations of “gold plating”.

4.1.4 Organisational Capability

Strategic objectives for organisational strengthening focus on quality, health & safety improvement, risk management processes, staff development and succession planning.

Resources will be applied to the development of a formalised Quality Management System covering all aspects of both EILs and ENLs business over the next 2 years. For ENL this programme will consolidate corporate, compliance, contractor management, distribution control, safety and engineering manuals, standards and policies in a coordinated set of documents that describe monitoring, continuous improvement and audit functions. The desirability of formal certification to ISO 9000 will be considered after the completion of the project.

Regular external review of existing contractor safety management systems and distribution operating practices identifies areas where improvements to existing safety related processes can and are being achieved.

4.2 Legislative Requirements

The following statutes are of particular relevance to this asset management plan:

- The Electricity Act 1992
- The Electricity Regulations 1997
- The Electricity Industry Reform Act and Amendments
- Health and Safety in Employment Act 2003
- Resource Management Act 1991 and Amendments
- The Commerce Act 1986, Specifically Part 4A, Electricity Information Disclosure Requirements 2004
- Electricity Governance Regulations 2003

Other statutes apply to the business as a whole, but are peripheral to the asset management philosophy.

4.3 Current Level of Service

The key customer service levels that relate to Asset Management are:

- Supply reliability and security
- Supply quality, e.g. voltage drop, voltage fluctuations, harmonics
- Fault response repair times
- Notification of shutdowns
- Cost of supply

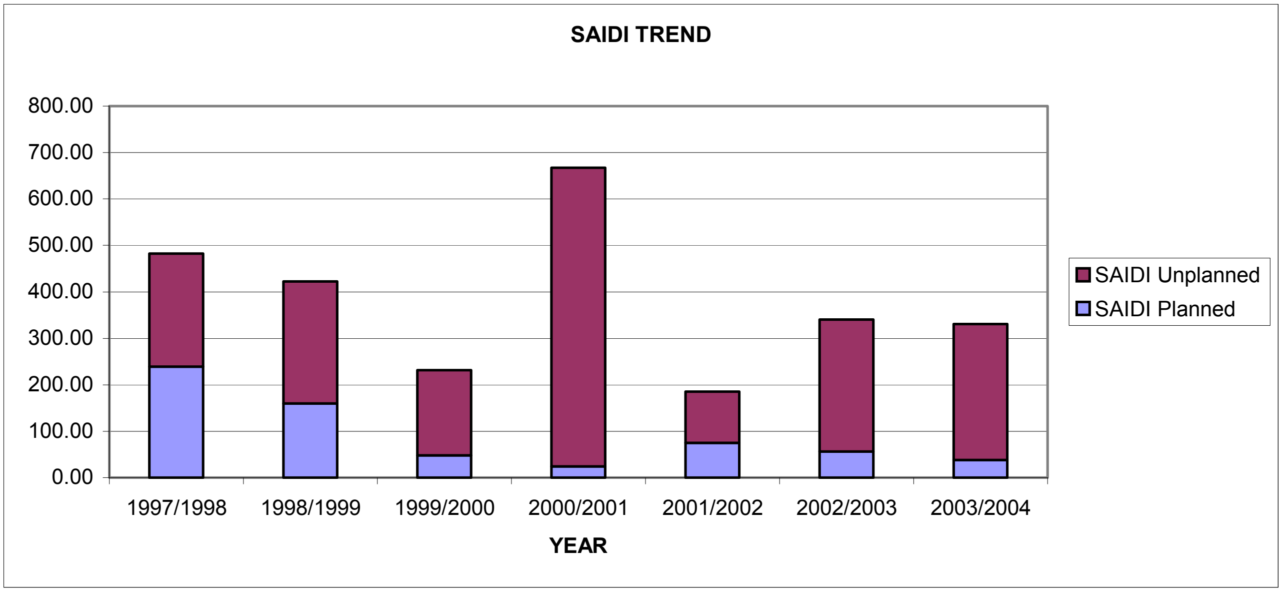
Measurement of customer satisfaction regarding service is achieved via feedback from energy retailers and consultation with customers. Measurement of the service performance is carried out using internal physical measures and targets. Alterations to targets for service levels are the responsibility of the management team and annual reviews are incorporated into business planning activities.

Network delivery efficiency is indicated by cost performance measures that are disclosed each year together with targets.

4.3.1 Reliability and Security

Security considerations and the derivation of appropriate standards for ENL are discussed in Section 6.0 of this AMP.

The primary indicator of reliability performance is the SAIDI index, trends for which are illustrated below.

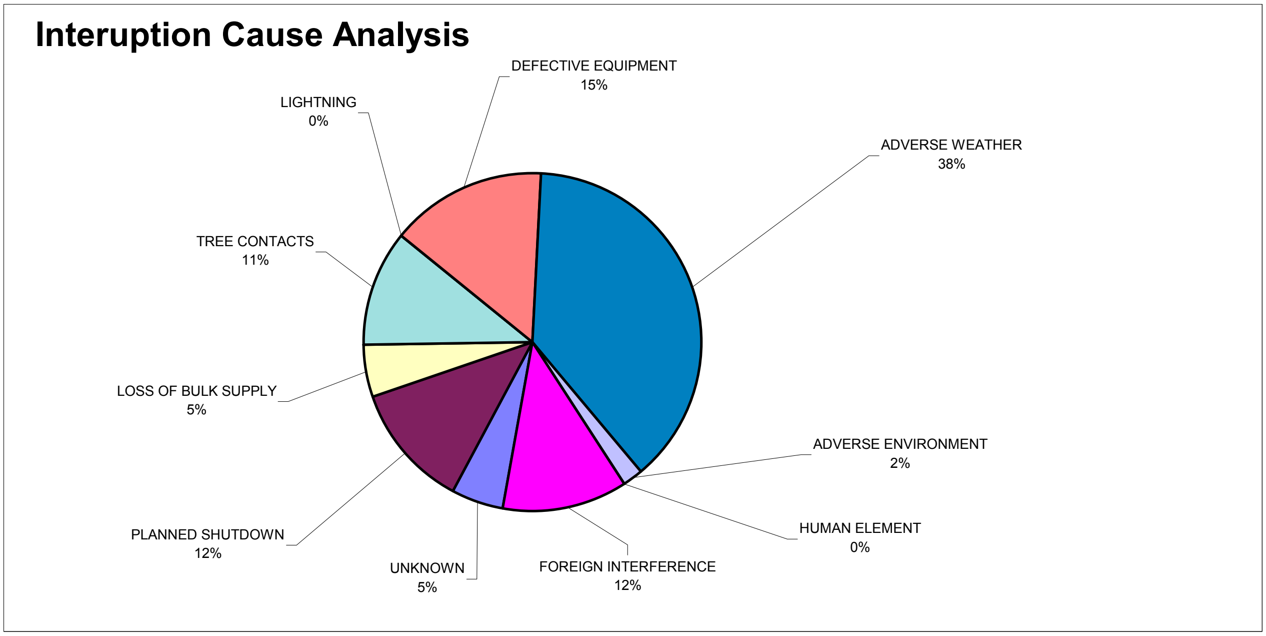


Besides inherent system security, a wide range of factors impact on observed reliability performance.

Trees are an increasing problem in a region with a fast growth rate and developing forestry industry. The Electricity (Hazards from trees) Regulations 2003 now provide clear definition of the rights and responsibilities of both tree owners and lines companies. ENL is implementing a process and procedures which will ensure full compliance with tree regulations and accordingly mitigate tree related reliability and safety issues.

Protection is an area where technology delivers large reductions in outages. ENL has developed this technology since 2001 which in combination with automation, and optimisation of isolation points has improved performance, number of customers affected, and fault restoration time. Lifecycle management plans for these assets in Section 8.0 address technology improvement and future deployment.

Cause analysis during the last year provides the following spread:



Planned shutdowns accounted for 12% of outage duration during 2003/04.

Actions have been taken to reduce the level of unknown causes previously 20%, over recent years, since it frustrates an effective management response. Initiatives have included improved field fault reporting, automation projects, and follow-up patrols to short lived faults.

The 38% adverse weather component is in effect indicative of poor asset condition, since power lines are designed for outdoor conditions for the duration of their design life with the conductor becoming a predominant issue. Under design has not been an issue with the exception of extreme snow loading.

Foreign interference is high at 12%. This figure is driven by vehicles/pole collisions. Increasing technology will minimise the impact of these faults. A long-term objective is to clean down structure design and increase separations to reduce bird strikes and animal interference.

Defective equipment is given as the cause for 15% of outages. Faults in this category tend to have long repair times/high customer minutes.

Causes are generally condition related resulting from assets remaining in service after their optimum replacement date. However there is an increasing trend for newer equipment to fail prior to expectations largely due to reduced quality and workmanship at manufacture. Standardisation on proven product, rigid specification and quality control procedures has been introduced to address this issue.

Defective equipment events (particularly pole failures) have reduced significantly since completion of the major Compliance Management Project undertaken in 2001 – 2002. This captured many age-related condition issues and brought performance more into line with normal expectations. Improvement of the ABS asset condition is being managed via long term replacement programs.

Conductor failure is expected to predominate in the future. This is addressed in lifecycle replacement plans.

4.3.2 Supply Quality

The quality of supply is measured in terms of:

- Voltage flicker complaints
- Low voltage complaints
- Harmonic content in supply
- Radio Interference complaints
- SCADA monitoring and deviation reports

The legislation and regulations that determine supply quality requirements include:

- The Electricity Act 1992
- Electricity Regulations 1997
- The Commerce Act 1986

Deviations from regulatory limits and poor supply quality levels are recorded in the network defects database as soon as they are identified. Corrective actions are carried out as soon as practicable. Issues requiring longer term supply quality improvement to the network asset are incorporated into the company design standards and management plans for the affected asset categories.

4.3.3 Fault Response Performance

The control operations staff and/or faults service contractor record response times for network outages. The delegated engineering officer is responsible for reviewing the recorded figures and implementing improvements or corrective action when necessary. Comparisons of the response times are made with benchmark values to indicate trends. Outage duration and repair time components are incorporated into the performance indices for industry benchmarking.

4.3.4 Notification of Shutdowns

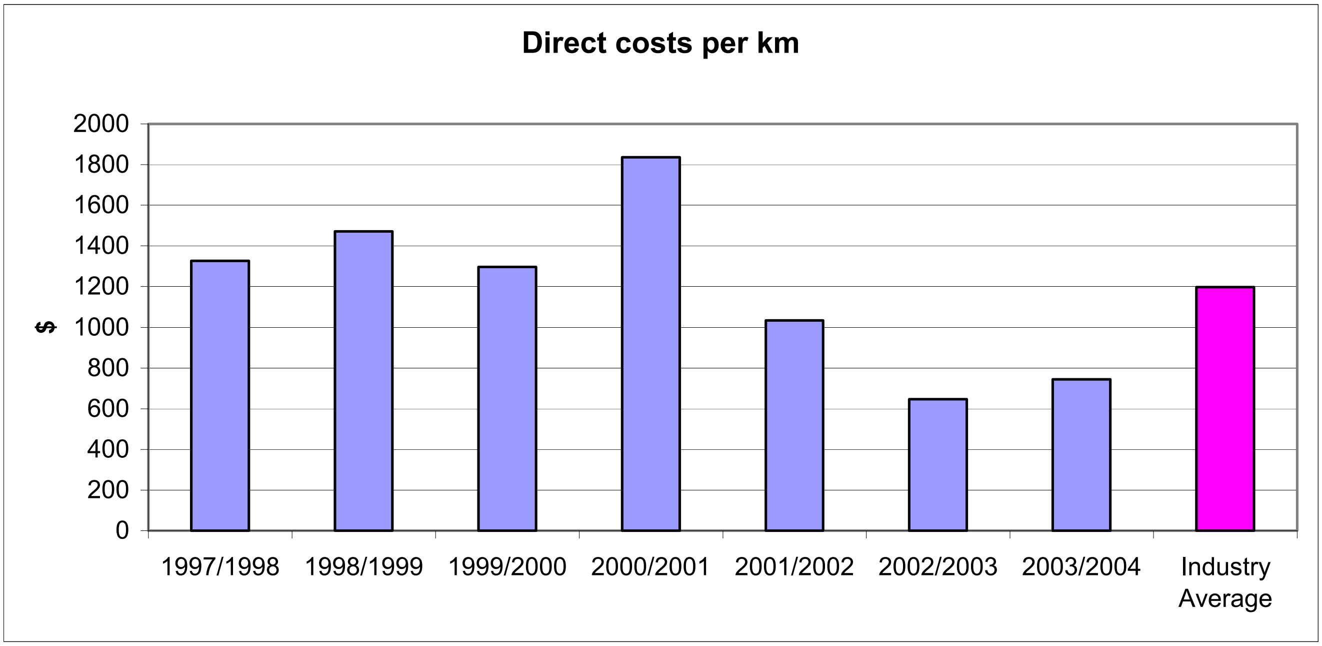
ENL has implemented the industry standard profoma email notification process for advising planned outages. This process identifies affected ICPs and standardised shutdown information is emailed to relevant energy retailers. The energy retailers in turn advise their customers accordingly.

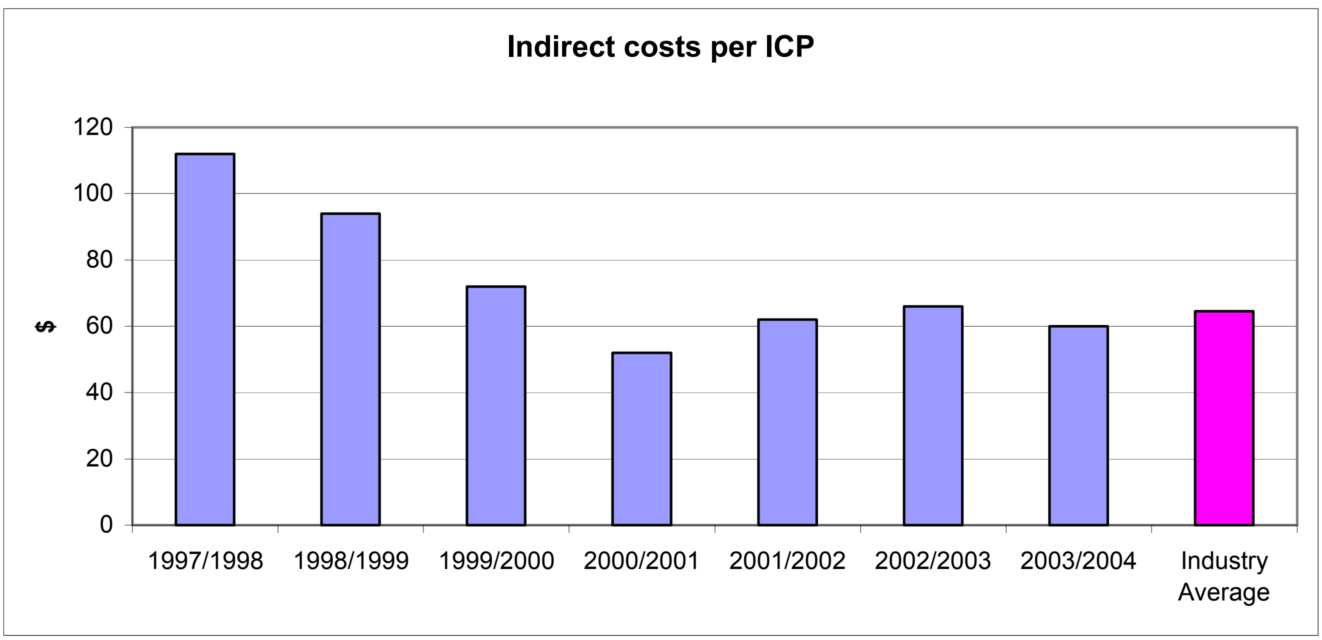
Notification timing and shutdown information provided is in accordance with the current Use of System Agreements.

4.3.5 Delivery of Efficiency

Cost performance measures that are disclosed each year include:

- Direct cost / km
- Indirect cost / connection





The trends are in line with current business targets and regulatory requirements.

4.4 Desired Levels of Service

ENL's performance has been compared against 4 benchmarking groups for the purpose of determining its desired position in the market.

Information has been derived from analysis of 2002/03 information disclosures. The 4 benchmarking groups are as follows:

1. All New Zealand lines companies: If the long term expectation is that only a quarter of the existing companies will exist then it is logical that ENL targets being in the top quartile in terms of performance to justify its existence.

2. Rural line companies i.e. those with a customer density of less than 10 connections/km of network. ENL is a network of rural nature despite a large urban centre. This benchmark group helps identify what characteristics of rural networks are performance disadvantages and what are commonly held myths.

3. A selected benchmark group of similar size, customer density, urban/rural split, and transmission remoteness. This group provides the most accurate measure of our existing performance.

4. Ernst & Young's Top 10 pick. This group gets used publicly as an independent assessment of company performance. While their model of what makes a lines company efficient clearly favours separated standalone lines businesses that were urban based, there is still a wide representation of companies from all the above groups within the top 10.

Targets have been set to place ENL in an average position. At the same time annual improvement has been smoothed to a constant rate over that period.

Targets are set only as drivers to deliver a path of improvement. Extrapolation limits the probability of achievement the further projections are extended. Therefore targets should be used to measure trends and monitor short-term performance.

DISCLOSED SERVICE PERFORMANCE TARGETS							
	2003/04 Actual	2004/05	2005/06	2006/07	2007/08	2008/09	Average 2004~2009
Interruptions							
B Planned	112	76	72	68	68	68	70.4
C Unplanned	247	135	130	123	123	123	126.8
Faults/100km							
Total							
50 kV	1.72	3.1	3.0	2.9	2.9	2.9	3.0
33 kV	5.83	0.0	0.0	0.0	0.0	0	0.0
11 kV	8.18	6.8	6.6	6.5	6.5	6.5	6.6
Total	7.67	6.0	5.8	5.7	5.7	5.7	5.8
Underground							
50 kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33 kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11 kV	4.09	0.92	0.91	0.90	0.90	0.90	0.91
Total	4.0	0.92	0.91	0.90	0.90	0.90	0.91
Overhead							
50 kV	1.72	3.1	3.0	2.9	2.9	2.9	3.0
33 kV	5.83	0.1	0.1	0.1	0.1	0.1	0.1
11 kV	8.36	6.8	6.6	6.5	6.5	6.5	6.6
Total	8.0	6.0	5.8	5.7	5.7	5.7	5.8
SAIDI							
Total	331	300	285	271	258	258	274.4
B Planned	38	45	43	41	39	39	41.4
C Unplanned	293	255	242	230	219	219	233
SAIFI							
Total	1.94	2.00	2.00	2.00	2.00	2.00	2.00
B Planned	0.20	0.30	0.30	0.30	0.30	0.30	0.30
C Unplanned	1.73	1.70	1.70	1.70	1.70	1.70	1.70
CAIDI							
Total	171	150	143	136	129	129	137.4
B Planned	188	150	143	137	130	130	138
C Unplanned	169	150	143	136	128	128	137

Notes

1. Overall PI's are from SCI

2. Planned SAIDI = 15% of Total

3. Targeted Control Regime 5 Year
Average SAIDI = 366 , SAIFI=3.34

Note: Actual figures used for 2003/04 exclude Transpower outages.
Full Information Disclosure results for 2003/2004 have yet to be audited.

Targets as per SCI – Direct Costs per km					
	2004/05	2005/06	2006/07	2007/08	2008/09
TOTAL	744	743	714	714	714

Note: Industry average for 2002/03 $1,198.

Targets as per SCI– Indirect Costs per connection					
	2004/05	2005/06	2006/07	2007/08	2008/09
TOTAL	60	60	60	60	60

Note: Industry average for 2002/03 $65

5.0 FUTURE DEMAND

The production of a load forecast enables assessment of the likely future configuration of the power system, after which it is possible to determine a sensible development programme.

Although this programme should ensure the most effective utilisation of assets possible, it is important to note that the objective of an optimally planned system is unlikely to be able to be achieved in the short term. Given that ENL faces the challenges associated with serving a consumer base that is very different to that it has historically planned for, it is more realistic to expect the objective to be achieved over the 10-year planning period.

5.1 Factors Influencing Demand

ENL has experienced several years of high base load growth and expects this to continue. However growth is uncertain and driven by the regions economic outlook, and in the longer term, by changes in technology, development of distributed generation options, etc. Growth is particularly sensitive to the pattern of development of the regions forestry resources and industry. National gas reserves will be an issue in the long-term. Major factors impacting on demand in the region are discussed in the following sections.

5.1.1 Regional Characteristics

The Gisborne District is an area of 8,351 square kilometres on the East Coast of New Zealand's North Island. The district is relatively remote with two main population centres – Gisborne and Wairoa, with populations of 32,600 and 5,200 respectively.

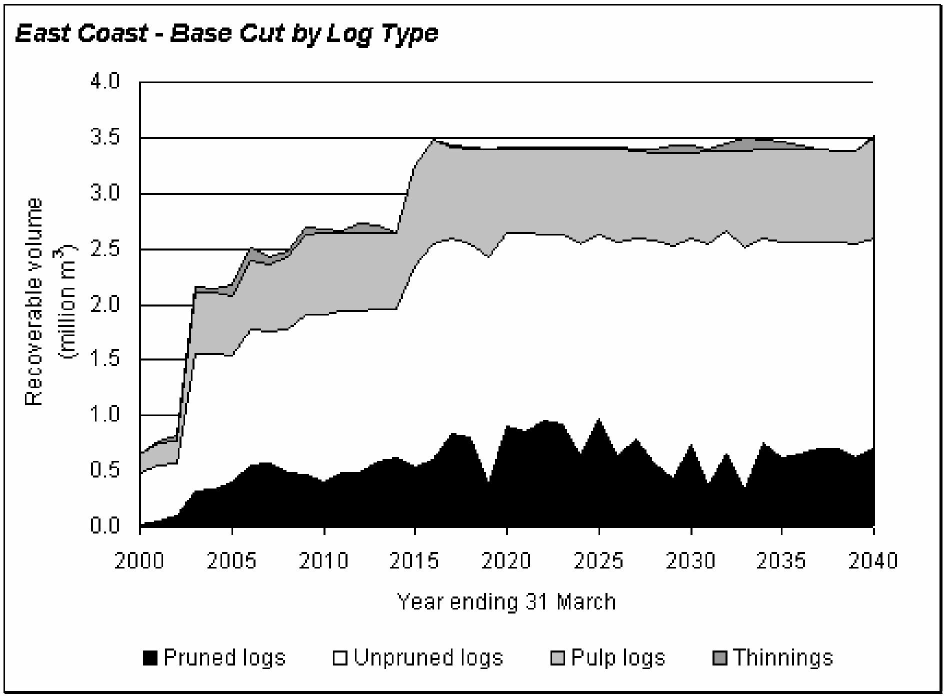
Geology in the region is relatively young, presenting landslide challenges to network design. Similarly the region has a high risk of earthquake and Tsunami. The exposed nature of the East Cape ensures wind and storm events are a feature network design must cope with.

Load demographics have shifted from a predominantly rural load base to urban dominance concentrated in Gisborne city. Commercial load is exhibiting high growth and has become the predominant load group serviced by network. This load group, being the local economies wealth creators, is the focus of changing service requirements in Eastland Network Ltd's asset optimization.

However there remains high growth associated with tourism and holiday housing. Summer load peaks are developing in parts of the network. This is added to by changing consumer behaviour such as increased use of air conditioning.

5.1.2 Forestry Growth

A very large increase in forest harvesting is predicted for the East Coast area. The Ministry of Agriculture and Forestry's *National Exotic Forest Description 2000* provides forecasts of the total recoverable volume of logs through to 2040. Current log volumes are expected to approximately triple to around 2.5 million m^3 within 5 years, and increase still further to around 3.5 million m^3 approximately 10 years after that.



Source: *National Exotic Forest Description: National and Regional Wood Supply Forecasts 2000*

The existing Juken Nissho Ltd ("JNL") mill can be expanded to accommodate approximately 36% additional throughput. Beyond that, however, additional harvest volumes will require additional mills. The forecast growth in harvest therefore requires at least an additional two mills within five years, assuming that the ratio of raw log exports to the total harvest size remains approximately the same, and perhaps another large mill within a further ten years. Further mills may also be required, including less energy-efficient smaller mills.

Like the existing JNL plant, a large mill would generally employ a Combined Heat & Power ("CHP") unit fuelled by waste wood and gas to deliver the larger part of its gross energy requirements. The electricity load requirements associated with two new plants in close proximity would be approximately 7 to 10 MW based on the net requirements of the existing mill. The distribution system in the Matawhero area, where processing plants are most likely to locate, would therefore need to accommodate additional load of up to 10 MW in the short term alone. Impacts on the transmission system would of course be greater and reflect the aggregated regional load increase, perhaps in the order of 25 to 30MW within a ten year period. This capacity margin could be minimised through embedded CHP plants exporting surplus power to the distribution network.

The Tarawhiti Development Taskforce report estimates that forest harvesting and processing could generate 15,000 – 20,000 additional jobs in the region. As a result of the additional connections and income driven increases in electricity consumption, domestic loads would increase.

On a final note, the regional benefits and anticipated increases in load will be limited if most logs are exported unprocessed, and this constitutes a real investment risk given the history and development of the New Zealand forestry sector.

5.1.3 Gas Resources

Undeveloped gas resources existing in the region could be a source of relatively cheap electricity generation in the Eastland region and radically alter power flows. Significant new generation could reduce net power inflow to very low levels, or possibly even make the Eastland region a net exporter of electricity. There is a belief among the industry that there will be a strong demand for gas in the East Coast because of the maturation of the pine plantations, the increased power generation requirements, and the high costs of delivering gas from the Taranaki region to the East Coast.

5.1.4 Changes In Technology

Advances in technology that replace the need for capacity in a distribution network are clearly evident on a 10 year horizon. The need for investment in assets with a 40-year life is therefore clearly subject to challenge. This is particularly true of capacity investment in the rural network, where small scale distributed generation will become a more economic alternative in remote locations.

Transmission and distribution lines exist for the sole purpose of transporting electricity from where it is generated to where loads are located. Logically, if generation could be moved closer to loads, then there would be less need for transmission and distribution. In this sense, new generation "competes" with electricity lines businesses/investments. This is particularly true of distributed generation (and direct substitutes such as direct solar water heating). Larger embedded generation plants are less of a threat for distribution networks, but pose a significant risk of bypass for transmission networks. These technologies can also be used as substitutes for network upgrades.

Potential new generation in the Gisborne region includes new biomass generation to accompany additional forestry mills, larger biomass plant(s) that would produce more power than required by the mills, gas generation plant to take advantage of spare capacity in the NGC pipeline or new gas discoveries, small gas turbines and hydro that could be operated as peaking plant to reduce peak demand, and other renewables such as the high wind and solar resources in the region.

ENL has the opportunity to use embedded and distributed generation to reduce need for transmission and distribution upgrades. ENL can also re-engineer the network during the current upgrade programme so that it is more suitable for a distributed generation environment. These issues are the subjects of a development strategy in preparation to minimise investment risk and lower electricity supply costs.

5.2 Forecast Demand

5.2.1 Analysis of Load Growth Trends

Comments on individual zone substations and load trends are provided below.

Te Araroa

Load growth is minimal, Growth change is smaller than weather pattern variance there are a few commercial ventures being developed in this zone, and installed capacity far exceeds demand. There are no load issues requiring attention at this substation. A 1MW Diesel Generator is connected at the Zone substation.

Ruatoria

The overall load profile is very flat with a winter peak. This suggests load is predominantly very low usage domestic installations relying on non-electric heating. This is expected in rural areas with good wood supply and low employment. Only minor load growth, if any, is expected, and this is likely to be dominated by weather pattern variance. A 1MW Diesel Generator is connected at the Zone substation.

Tokomaru Bay

The Tokomaru Bay substation has presented a peakier load profile than other coast substations in recent years. Substation capacity exceeds load requirements. Growth in terms of unit sales is high. This is attributed to summer/holiday load.

Tolaga Bay

Tolaga Bay is showing higher unit growth although this is small in absolute terms. Patterns indicate that this growth is the result of new connections rather than growth in consumption. Peak demand growth is appearing as an increased winter peak, which has also shifted to later in the winter season. A 1MW Diesel Generator is connected at the Zone substation.

General Comments on the Coast

Loadings on the Coast are lower than the installed capacities of the sub transmission system. The load profile is flat, and there are few commercial and industrial loads. From an economic viewpoint, high levels of sub transmission investment made in this area cannot be justified, but long distances require high voltage and bulk supply has to be concentrated. Security provision would therefore normally require large, redundant assets. ENL has adopted a design approach where security is provided by standby generation support.

This approach has the potential to deliver better service, reduce zone substation asset investment, and avoid 11kV network reinforcement cost. Actions already undertaken include removal of redundant transformers and replacement of outdoor switchyards with indoor 11kV switchboards providing room for generators on existing sites.

Kaiti

Kaiti Substation feeds a large predominantly domestic load at the northeast end of Gisborne. Capacity constraint has been mitigated by the shifting of load to the new Port substation. Current security issues will be resolved with the completion of the Kaiti-Carnarvon 50kV link in 2004/2005.

Port

This substation was commissioned in 2003/04 to provide for new growth in the port and CBD areas of Gisborne and support the adjacent Kaiti and Carnarvon substations. Additionally its facilitates the development of N-1 security with the completion of the Kaiti-Carnarvon 50kV link.

Carnarvon

This substation recovered to secure load levels prior to the loss of Watties (6 MW) in 1999, Strong growth and a flattening of the load profile since 1999 has encroached into the secure load rating. Customer activity has less seasonal characteristics and this substation no longer has a distinct winter peak. The Kaiti-Carnarvon 50kV link and Port substation will resolve security issues.

The City feeders show volatile load changes that are directly related to the prosperity of retailing sector and a shift to summer load has occurred that is probably the result of additional air conditioning and refrigeration. Changes in the pattern of development of the town centre have also impacted on feeder load distribution.

Parkinson

The load at this substation was relieved in 2000 after the construction of Matawhero substation but has had strong growth primarily seen by reinstatement of equipment from the Watties site in this area. The overall load profile is particularly flat but individual feeders have distinctly different characteristics, reflecting the mix of industrial, commercial, agricultural, and domestic loads on this substation. Both Cedenco and Montana now have dedicated feeders from this site. These industries are driving load growth at this substation.

The continued high rate of load growth at this substation, Carnarvon substation and the Matawhero substation has necessitated sub transmission development. This is reflected in projects being undertaken in 2004/2005 to install an additional transformer at Parkinson St. and develop a 50kV link between Makaraka, Matawhero and Parkinson St.

Makaraka

A 12.75 MVA transformer was installed at this switching station during 2001, taking load previously supplied via Parkinson, Carnarvon and Massey Road. This site is limited ultimately by the security capability between substations.

Patutahi

Overall growth at this substation is moderate and constant with a flat profile as expected in areas with cropping land use. The growth of lifestyle blocks on the Poverty Bay Flats is contributing to demand increases. Given load relief via the new substations at Makaraka and Matawhero there are no load issues at this substation. Reduction to a single 5MW transformer configuration is planned.

Pehiri

Pehiri load profiles indicate no appreciable growth with loading dependent on the operation of the quarry. It is strategically placed to facilitate potential forestry activity.

Ngatapa

This substation also has no significant growth and a very small peak. The load profile is typical for a sheep farming area with a clear winter peak. This site is key to provision of support to the Puha substation and Matawai area however 11kV line construction will be required to achieve this.

Puha

Puha is a relatively large rural substation that supplies a large area with no 11 kV backup capacity. Load growth in unit terms is low and the load profile very flat. A 1MW Diesel Generator is connected at the Zone substation which will support the load in part.

Matawhero

Matawhero substation was constructed in 2000 to release capacity at Parkinson Street and provide for additional meat processing load. This capacity has now been taken up and a second transformer was installed in 2003.

Wairoa (Transpower)

Direct 11kV network feeders have been rationalised back to Eastland Network Ltd's Kiwi substation. Total demand at this substation exceeds contingent capacity at peak periods when Eastland Network Ltd's Waihi generation is not injecting.

Blacks Pad

Tourism/holiday and lifestyle load growth at Mahia and dairy shed growth at Mahanga have presented an average growth of 5% at Blacks Pad since 2002. This is creating voltage and security limitations and upgrade planning is underway. The area is dependant on a 1MW Diesel Generator, installed to support both load and voltage for peaks. The development plan details upgrading work for the area.

Tahaenui

Stable load minimal change is forecast. The substation was installed in 2002 to overcome the inadequate 11kV supply originally used.

Summary

Zone substation capacities and present loads are shown in the following table. The loads shown are half hour maximum 2003/04 demands with normal load control policy in effect.

Forecast peak power demands by the end of the planning period are also indicated.

Growth forecasts have been averaged on a 10-year prediction to smooth out step increments introduced by new loads rather than base load growth.

Substation	Transformer Capacity (MVA)	Load 2003/04 (MW)	% of Installed Capacity	Growth (%)	Load 2014 (MW)
Te Araroa	1 x 2.5	1.06	40	1	1.18
Ruatoria	1 x 5.0/7.5	1.50	30	1	1.67
Tokamaru Bay	1 x 2.5	1.10	44	1	1.22
Tolaga Bay	1 x 5.0	1.23	24	1	1.69
Port	1 x 12.5	2.12	17	2	2.63
Kaiti	1 x 12.5	10.31	82	2	12.82
Carnarvon	1 x 12.5, 1 x 12.75	15.94	63	3	20.81
Parkinson	1 x 12.5	8.75	70	4	11.99
Makaraka	1 x 12.75	8.46	66	3	11.05
Patutahi	2 x 5.0	3.88	39	2	4.83
Pehiri	1 x 2.5	1.23	49	1	1.37
Ngatapa	2 x 0.5	0.54	54	1	0.60
Puha	1 x 5.0	1.90	38	2	2.37
Matawhero	2 x 5.0/7.5	7.6	76	4	11.69
TP Tuai	-	0.70	-	0	0.7
TP Wairoa	1 x 2.5 (11/33)	1.79	72	7	4.25
Kiwi	1 x 6.3	4.79	76	0	4.79
Blacks Pad	1 x 1.5 (33/11)	1.58	105	8	3.68
Waihi	1 x 6.3 (6.6/50)	4.81	76	0	4.81
Tahaenui	1 x 1.5 (33/11)	0.46	30	2	0.57

Typical daily load curves are given in Appendix 11.6. Daily load profiles still exhibit a large 6.00 p.m. load peak of over 8MW and a smaller mid-morning peak of 3MW. The base load never falls below 12MW with the trough occurring at approximately 3.00 a.m. each morning. The daily load profile is therefore very peaky and presents demand side management opportunities.

5.2.2 Overall System Growth

By projecting growth trends forward, coincident system peak demand has been forecast to grow from 57 MW in 2002 to 71 MW by the horizon year, 2014. The moderate overall growth rate of approximately 2% reflects anticipated levels of economic activity in the Eastland Region.

ENL has a Load Forecasting Model to help it predict the impact of accumulated load growth on its capacity requirements and security standards. It also allows scenario planning for investigating the impact of large loads associated with new processing plants and other industrial loads when applied at specific locations in the network.

The model works as follows:

- Profile Builder: Feeder load data is obtained from the SCADA system. Load profiles are created for domestic, non-domestic, and specific industrial consumers and reconciled so that they sum to known feeder level data.

  Zone substation, sub transmission line, and GXP profiles can then be built up.

- Load Forecasting: The number of connections and an assumed annual growth rate can vary each profile for each class of consumer.

- Scenario planner: Large loads and generation can be inserted at any sub-transmission node. i.e. zone substation. Resulting loads and their profile can be applied to PSSU load flow analysis to determine voltage, loss and security issues.

5.2.3 Forecast Accuracy and Variations

All demand forecasts are also subject to variation as a result of externalities such as weather and economic growth. Annual variations in these factors will create demand variations in the short term, whilst sustained trends are likely to cause more persistent departures from the forecast.

Varying the timing of planned work can accommodate forecast variances. Lower than expected load growth can be accommodated by deferral and faster than expected load growth by acceleration. Adequate notice is generally available for the type of work involved to undertake such acceleration, although major items of equipment can have long lead times and constrain the extent to which work can be performed ‘just in time’. ENL’s basis for network planning and operations is sufficiently rigorous and conservative to avoid serious capacity shortages and un-served demand.

Eastland Network Ltd does not however manage the transmission system planning. When presented with a transmission issue by Transpower Eastland Network Ltd assesses opportunity for alternative investments that deliver lower cost. Responsibility for delivery of transmission capacity and security and the associated investment risks belong to Transpower.

5.3 Load Control

The traditional pilot wire system predominantly used in Gisborne until 1992 was inflexible and expensive compared to the load control system that uses ripple relays and is well established in the wider Gisborne area. As it became more difficult to effectively fault-find ENL has phased out the existing pilot system in favour of more extensive use of ripple relays.

The Wairoa urban centre uses a pilot wire system with ripple relays deployed in the wider area. The customer relays are owned by the incumbent energy retailer. The retailer has decommissioned the load control relays used in Mahia.

The ripple load control system allows more sophistication in load control, but this needs to be combined with incentives to encourage installation of off-peak appliances in addition to hot-water cylinders. Energy retailer tariffs have not encouraged this type of customer investment in the past.
Changing this position is a process that requires the completion of an appliance life cycle and therefore will take in excess of 10 years to correct.

6.0 NETWORK DEVELOPMENT

6.1 Security Review and Standards

Security standards are used as the benchmark for providing an optimum level of security and fault tolerance to ENL customers. They are also used to assess the continued adequacy of the existing network as load grows. ENLs standard was derived during a detailed Security Review undertaken in August 2001, which also determined preferred solutions to security upgrades.

ENLs base security criteria apply to all network design and are as follows:

Class	Range of Group Peak Demand (GPD) MVA	Customer Impact	Security Level	Contingent Capacity	Time to Restore after 1st Interruption	Time to Restore after 2nd Interruption
D	> 25MVA i.e. Transmission or GXP or Sub-transmission rings	>15k	n-1	100%	Maintain 100% GPD less 12MVA. Remaining 12MVA within 3 hrs	Restore 100% in repair time
C	12 to 25 MVA i.e. Small GXP, primary CBD & urban zone substations	>7000	n-1	100%	Maintain 100% of GPD.	Within 3 hrs restore 90%, repair time 100%
B1	6 to 12 MVA i.e. Primary urban/Industrial zone substations	>3500	n	100%	Within 15 min restore 75%, within 3 hrs 90%, repair time 100%	Within 3 hrs restore 90%, repair time 100%
B2	3 to 6 MVA i.e. Single TX zone subs and urban meshed feeders	>1750	n	80%	Within 30 min restore 75%, within 3 hrs 90%, repair time 100%	Restore 100% in repair time
B3	1 to 3 MVA i.e. Rural zone substation, meshed feeders	>500	n	67%	Within 1 hr restore 50%, within 3 hrs 90%, repair time 100%	Restore 100% in repair time
A	0 to 1 MVA i.e. Rural feeder, urban spur, distribution transformers	<500	n	Note 1	Restore 100% in repair time	Restore 100% in repair time

Note 1: Refer to Section 4.3 and **Eastland Network** Customer Service Standards for LV Network backup, dual distribution transformer capacity or temporary supply criteria. [Temporary options include construction of prefabricated OH lines, HV or LV flexible surface jumpers or 300kVA generator supplies.]

The following philosophies are fundamental to meeting the security standards in the design of any network component:

- The ENL network is a low density, lightly loaded, distribution network. In a network of this character the provision of security via full redundancy can rarely be justified, is not cost efficient, and does not offer the best fault tolerance.

- The preferred method of providing contingency supply will be via excess capacity in network components.
- Transformer loading for both zone and distribution transformers is to comply with IEC354. This is to permit short duration overloading beyond nominal ratings under specified ambient and cyclical conditions.
- Alternative supply options will be built at the lowest voltage practical due to better inherent fault tolerance and flexibility with respect to interconnection.
- Cables will not be driven into duty cycle levels of loading. Eastland Network jointing practices and installation design do not provide for this mode of operation.
- Preference will be given to ring design for an alternative route instead of double spur circuits.
- In rural spur network the density of isolation points will be used to localize the effects of faults, to achieve customer service standards.

Specific network component provisions to ensure compliance with the security standard are presented in Appendix 11.1. The statement of growth and security constraint triggers for upgrade is provided in Appendix 11.2.

6.2 Risk Assessment

The following matrix records for each network related risk currently identified:
The success factors applied

- The weightings applied
- The assessment scores
- The resulting priorities

In general there is a strong correlation between risk priorities and current work program's. However it should be noted that risk is not the sole driver of work priorities. Risk priorities influence development plans but timings are also based on the need to co-ordinate projects.

The identified risks are addressed within the current work programs given in the Asset Management Plan. However annual review is necessary due to the rate of change in the network. This process captures new risks and adjusts priorities.

Action Plan Priorities Ranked by Risk Reduction Outcomes

Success Factor or Outcomes :

Reduced combined effect with other risks or increased combined provision
Improved Safety
Reduced SAIDI (improved service)
Reduced SAIFI (improved reliability)
Cost reduced
Return on investment required achieved or increased
Economic Impact to Community Reduced
Compliance and Environmental Responsibility
Public Acceptance
Meets Urgent Need

Ranking Criteria (against each Success Factor) : 1 to 10
0: No Impact 2: Low Impact 5: Medium Impact 7: High Impact 10: Crucial

Priority	Action Project Number and Title		Criteria Weightings										Score
			20	10	5	10	10	5	10	15	5	10	1000
1	31	Red taged pole replacement high density	10	10	10	6	7	8	9	8	10	8	860.00
2	55	Carnarvon St Security	10	10	10	8	6	5	8	10	0	7	815.00
4	32	Red taged pole replacement rural	8	9	10	4	7	8	9	7	9	8	770.00
5	54	50kV line from Carnarvon St to Kaiti	10	10	8	5	6	4	6	10	0	6	740.00
7	57	Parkinson St Security	8	10	8	9	6	4	6	9	0	6	725.00
11	58	50kV line Parkinson Matawhero JNL	8	8	8	9	6	3	4	9	0	6	680.00
12	33	Red taged pole replacement remote	6	8	10	2	5	9	9	6	8	8	665.00
13	39	Quadrant ABS replacement	7	2	10	3	1	8	9	10	10	8	660.00
14	38	Single Phase line conversion 300kM	5	7	0	9	8	9	7	8	0	7	645.00
16	30	Correct Low voltage Raupunga feeder Wairoa	9	10	10	4	4	3	8	4	0	4	605.00
18	24	33kV line extension Blacks Pad to Mahia	6	10	4	4	4	2	8	8	0	5	580.00
19	77	Raupunga/Frasertown Tie Capacity	8	8	0	5	4	3	5	9	0	3	560.00
21	35	Switchgear Automation	6	5	0	5	3	8	4	9	2	6	535.00
22	5	Customer RISK Provisions	6	3	0	8	10	0	4	8	0	4	530.00
23	76	Kiwi Substation Zone Wairoa CBD Security	4	10	6	7	4	4	3	8	0	4	530.00
26	1	Relax Voltage Standards for Tx Capacity	9	3	7	7	10	5	0	0	0	4	480.00
28	8	Neutral Earthing Resistors	10	7	10	2	1	6	0	0	10	3	460.00
34	74	Lowe St CBD Security	6	10	0	6	2	2	2	6	0	1	430.00
35	79	Tuai Supply	8	7	0	2	1	4	2	7	0	2	425.00
36	21	Matawai Supply security from Ngatapa	4	6	0	2	4	3	7	7	0	3	420.00
37	34	Correct Low road clearances	6	6	10	1	1	2	5	3	6	3	415.00
38	6	OLTC 110/50kV Transformers	8	3	8	7	5	4	0	0	0	4	410.00
40	2	Improve Load control capability	7	3	3	6	7	6	0	0	0	6	405.00
41	7	Install load peaking plant	2	4	3	7	4	8	0	6	0	7	405.00
45	60	Puha Security	6	7	0	3	2	2	0	8	0	2	390.00
47	3	Improved Power Factor Correction	6	3	6	6	8	5	0	0	0	3	375.00
51	42	Magnefix replacement (Fires)	5	0	2	2	1	7	2	7	8	2	360.00
52	4	Reduce Network Distribution Losses	4	3	5	4	8	7	0	0	0	6	350.00
53	47	LV conductor upgrades	5	5	8	2	6	4	0	0	0	4	330.00
54	48	Service Lines Capacity/Insulation	5	4	8	1	5	5	0	0	8	2	325.00
56	26	Tuai Voltage Correction	8	7	4	1	2	1	0	2	0	0	315.00
58	11	Aggregate GXP's Gisborne and Wairoa	6	4	0	3	6	8	0	0	0	1	300.00
59	44	Pillar Box Dammage	4	6	10	0	0	4	0	0	8	3	280.00
60	66	JNL Security	8	5	0	3	0	0	1	2	0	0	280.00
61	65	Cedenco Security	8	4	0	2	0	0	1	2	0	0	260.00
62	71	Montana Security	8	4	0	2	0	0	1	2	0	0	260.00
64	25	Kaiti Tolaga Voltage Correction	4	7	4	1	4	1	0	2	0	0	255.00
65	46	Meter/pillar replacement	3	5	9	0	0	0	0	0	8	3	225.00
66	45	Exposed LV pannels	4	3	8	0	0	0	0	0	8	3	220.00
67	37	Tapped termination replacement	4	0	0	1	0	3	2	4	2	1	205.00
69	67	Hospital Security	4	7	0	1	0	0	1	2	0	0	200.00
70	68	Affco Wairoa Security	4	5	0	3	0	0	1	2	0	0	200.00
72	28	Enviroment oil contamination	2	5	10	1	0	2	0	0	1	1	175.00
76	43	Distribution Transformer Earths	2	2	7	0	0	0	0	0	6	2	145.00
78	27	Earth Mat Upgrades	2	3	8	0	0	0	0	0	6	0	140.00
79	72	Hershell Rd Feeder Security	1	3	0	1	0	0	1	4	0	1	140.00
80	73	Airport Security	1	6	0	1	0	0	1	1	0	0	115.00

6.3 Network Investment Strategy

ENL completed a review of its network investment policy in August 2002, which sets out the policies that will apply to generation, transmission, distribution and load based investment requirements. Due to the strategic nature of this document only overview level detail is recorded in Appendix 11.4.

6.4 Loss Design Standards

Distribution network companies do not suffer a cost penalty for high losses. Hence there is little investment signal for reducing losses. This would imply that if voltage standards can be maintained then it is a valid commercial approach to minimize capital upgrades by not maintaining low loss levels.

It can also be argued that it is more economically efficient for the community to pay for losses than to fund capital expenditure particularly on rural feeders with poor economics. However in ENL's case where transmission is constrained the value of reducing losses can be measured against:

1) The cost of kWh of avoided transmission
2) The cost of new investment to increase capacity

Networks also have an obligation to manage their networks to good industry practice.

While voltage problems are not widespread on the network they do exist. An indicator of high losses is voltage sensitivity to load regulation. These issues are regularly evident in the following areas within ENL's network.

- Frasertown-Raupunga ring
  Essentially distance is beyond the capability of 11kV reticulation and sub transmission support is required.

- Mahia
  A large seasonal load at the end of the feeder suggests conductor reinforcement and sub transmission extension is required.

- Matawai
  Load, distance and voltage contribute to marginal performance.

- Tatapouri
  The long distance between Kaiti and Tolaga substations combined with high growth at Wainui is exceeding the conductor capacity and the Tatapouri voltage regulator limits.

- Ormond
  Load, distance and voltage contribute to marginal performance

While losses are higher in certain other locations the number of supplies affected is small and load diversity may mitigate this to some degree. If the areas identified above were to see significant load growth, voltage performance would quickly become unsatisfactory.

When designing new networks or replacing existing networks the following loss standards are applied.

	Design %	Max. %
Sub transmission Lines	1	2
Zone Transformers	1	2
Distribution Lines	2	5
Distribution Transformers	2	4
LV Distribution	3	6
TOTAL	9%	19%
Non-network losses		
Service Line	3%	
Metering	2%	
Installation	3%	
TOTAL	8%	

ENL's total system losses are 8.2%. This is considered to be in the medium to high quartile. Compared to the standard it shows that there is considerable diversity in losses in components and in load (of which loss is a function).

Old zone transformers offer the greatest opportunity to reduce losses on ENL's network. There are 4 banks of 4 single-phase units on the network. These transformers have losses in the order of 6% as a result of the following factors:

- High loss iron (all pre-1964 development using steel alloy).
- 4 separate units contain more iron to magnetise.
- Sub-optimal load.

In all cases savings in losses (valued at transmission cost only) and reduced maintenance justify replacement with modern 3-phase IMP units within a 5 year pay-back period. During 2001 dual transformer banks were eliminated at all rural sites except Patutahi.

Location	Capacity MW	Losses kW	Value p.a. $
Tolaga T1	5	300	40,000
Puha T1	5	300	40,000
Patutahi T1	5	300	40,000
Patutahi T2	5	300	40,000

The replacement of these transformers will allow deferal of new transmission capacity and is detailed in section 8.A.7

Analysis of feeder losses is provided in Appendix 11.3.

Despite losses being high in terms of percentage, on some rural feeders the cost of reconductoring is prohibitive unless needed for other reasons or attended to as part of a renewal program. Reactive support in the form of static capacitors is a viable option on rural feeders where:

- Losses exceed 5%
- Loads are less than 400kVA
- Losses exceed 27kW

Capacitors are expected to cost in the order of $10,000 per site. They are not suitable on tie feeders or areas with significant controllable load. In urban areas bulk correction at Transpower's connection is considered more effective.

In summary, approximately 7 feeders on the network are considered suitable for the application of reactive compensation by capacitors. However there is currently no commitment to this option as distributed generation strategies are being implemented which will provide for voltage support, reducing losses at high load times.

6.5 Other Issues

6.5.1 Transmission Development

The Gisborne Transpower Grid Exit Point faces constraints over the next 10 years, resulting from both the capacity of the 110/50 kV transformers and the volt drop on the 110 kV lines from Tuai. Meeting security standards is the main driver behind the need for upgrade. As load grows the security levels associated with Gisborne Substation will continue to diverge from this standard.

As discussed in Section 5.2, the timing of upgrades is very sensitive to load growth forecasts. To cover uncertainty ENL has concluded that provisional contingency capacity in its own network and Transpower's is needed now to cover the difference in planning/construction times and the installation of new load.

A summary of our planning conclusions is as follows:

- ENL is to carry 10 MW of excess capacity at key locations in its network to cover the 2 year lead time it would face providing capacity for a large timber processing plant.

- To provide for ENL's security standards the total capacity at Gisborne supply point needs to be increased. Options to achieve this increase include installation of an additional 30MVA transformer or replacement of the existing transformers with 60MVA 3 phase units, fitted with OLTC. The existing Tuai-Gisborne 110 kV lines have a normal (both lines in service) capacity of 65 MW and a contingent (one line in service)

capacity of 49 MW. The transformer equivalent normal/contingent capacity is 60/37 MW. The duration a single transformer is permitted to run at this contingent duty is shorter than loading currently demands.
This assessment is made in the absence of any specific reference to transformer constraints by Transpower, in their Security Forecast.

- Higher load growth rates will impact ENL's decision to install a second GXP at Patutahi. It is intended that this GXP would ultimately eliminate the existing Gisborne GXP.

- At existing forecasted demand growth rates the 49 MW contingent line capacity becomes a constraint in 2004. In order to overcome future security constraints associated with the 110kV lines Generation development is the preferred solution. Longer-term solutions include construction of an additional line from Tuai, reconductoring of the existing lines and Base load generation plant. Current expectations are that an additional line will be required from 2011.

- The 65MW, both lines in service, capacity will become a constraint in 2009 at forecasted demand growth. This constraint can be deferred by the use of distributed generation capacity.

- Following construction of a third transmission line a GXP will be required at Patutahi to avoid constraints arising in ENL's 50kV sub transmission network.

Eastland Network Ltd believes that alternative investment opportunities on its own network can solve transmission security constraints in the short term more cost-effectively. Further load management and peak lopping plant may defer capacity upgrades in the medium term. Commitment to transmission upgrade is therefore deferred until the actions currently in progress are concluded and the impacts on transmission capacity are confirmed. Preparation is underway to secure easements and design an additional 110kV line from Tuai to Patutahi.

The rules surrounding lines companies funding transmission investment need to be clarified. Lines companies need to be allowed to treat such investment as outside of the CPI-X pricing regime.

Other Factors

To achieve the excess capacity buffer and corresponding security levels in the sub transmission network ENL is currently developing the urban line into 2 rings. In the medium term a third sub transmission ring accommodating a 2nd GXP will be required.

Sub-transmission development is conflicting with Telecom's network in terms of unacceptable induction levels in their assets during fault conditions. Neutral earthing resistors (estimated at $260,000) are to be co-ordinated with any upgrade at Gisborne. NER's affect the ability to restrict over voltage situations during faults, so careful investigation of insulation coordination will be required on all 50kV assets.

Eastland has requested that our demand at all GXP's be aggregated to Tuai as this allows effective management of load between the two networks. An economic argument was prepared to support our request but to date Transpower have advised that this will not be considered as it is not provisioned for in their pricing methodology.

Eastland continues to be severely disadvantaged by Transpower's pricing methodology. Our response has been to implement by-pass options.

Costs of supply for the Tuai connection have triggered investigation into alternative supply options. ENL is progressing its provision of an alternative supply for Tuai customers, which is closely linked to other sub transmission development in the Wairoa district.

6.5.2 Uneconomic Rural Lines

Calculation of value objectives has indicated the need to reduce value in remote and rural areas ENL has developed a strategy for management of uneconomic lines. Assets classed as rural (non-remote) will be allowed to depreciate to an average remaining life of 13 years by 2011. The assets will then be maintained at this level. Assets classed as remote will also be permitted to depreciate to an average remaining life of 13 years by 2008. Following this the lines will be maintained at this level via a combination of renewal at lower cost, service line handover and cost contribution strategies. Alternative energy supply solutions are also expected to be part of the economic outcome.

3-Phase to 1-Phase Conversions

Renewal of the remote assets at a lower cost design solution can be achieved via reduction to single-phase in place of 3-phase construction.

Investigation of a number of construction options and voltages have been considered. The most economic solution for the terrain on ENL's network appeared to be 22kV single wire earth return. However other factors including new easement negotiation, telecom interference issues, and re-insulation costs, have now been considered and suggest conversion to single phase 11kV is the most practicable in terms of a viable and sustainable solution.

Because the ODV already assumes optimization of the existing 3 phase construction to single phase construction, the gains that can be expected are greater than that indicated by value changes. The actual cost of maintaining the existing construction standard is far greater than the return permitted on an optimized asset. This is compounded by the fact that the assets in question have exceeded their economic life and cost approximately three times as much to maintain as asset in optimum condition. New assets have near nil operating costs for approximately 20 years. These factors are sufficient to make such replacements an economic proposition.

300km of network in the Gisborne region in uneconomic zones has provisionally been identified as suitable for conversion.

It should be noted that:

- A number of low consumption supplies will be disconnected (at customers option)
- Service line costs will remain the customers responsibility, and
- Some customers will face additional costs of replacing 3 phase motors with single-phase motors.

Preliminary communications indicate that customer contribution options to fund the rebuild work are unacceptable. In addition there is no mechanism under the Targeted Control Regime to recover costs via specific price schedules. ENL is continuing to discuss and negotiate with regulatory authorities on an appropriate mechanism to address the viability of having uneconomic lines.

Further detailed work is required before this expenditure can be approved and the programme developed for inclusion in work plans.

6.6 Network Development Summary

Detailed load flow analysis has been conducted to assist in identifying solutions to the issues related to security, risk, loss correction, business performance and transmission options reviewed above. Timing of the work is largely determined by expected load growth.
Results of analysis and proposals are detailed in the Network Investment and Development Plan.
A summary of development plan actions since 2002 and for the next 2 years is tabled below. Costs for provisional projects beyond 2006/07 are excluded from section 9.1.1. at this stage. Timing and costs will be reviewed as the projects are developed and growth forecasts revised. The 2002/03/04 figures are included because a number of the major projects are in progress as the upgrade triggers have already been reached.

Development Plan Summary Description	Total Cost	2002-03	2003-04	2004-05	2005-06
Install T2 at Matawhero	$ 750,000	$ 498,000	$ 252,000		
11kV Tie cable Reads Quay to Port substation	$ 354,000		$ 354,000		
Close 50kV City ring	$ 2,109,868	$ 40,255	$ 353,596	$ 1,716,017	
Close 50kV Matawhero Parkinson ring	$ 2,380,000		$ 583,312	$ 1,796,688	
2nd Transformer at Parkinson St	$ 865,000	$ 49,693	$ 279,307	$ 536,000	
JNL Substation (1st Transformer)	$ 1,398,600	$ 49,804	$ 266,565	$ 1,082,231	
50kV Conductor Upgrades Makaraka	$ 280,348	$ 280,348			
Port Substation Construction	$ 860,000	$ 387,433	$ 472,567		
Whangara Substation Provision	$ 1,000,000				

Development Plan Summary Description	Total Cost	2002-03	2003-04	2004-05	2005-06
JNL 2nd Transformer provision	$ 750,000				
Transformer Patutahi Provision	$ 500,000				
Diesel Gensets Eastcoast TeAraroa/Ruatoria	$ 1,301,500	$ 1,076,233	$ 34,733	$ 60,000	
Diesel Gensets Puha/ Patutahi	$ 1,280,000	$ 984,157	$ 135,843	$ 160,000	
Diesel Gensets Mahia/ Frasertown	$ 1,284,000	$ 926,280	$ 137,720	$ 220,000	
Option Additional Diesel Gensets Eastcoast	$ 1,300,000				
Connection of Customer installed Generation	$ 50,000				
Option 3rd 110/50kV Transformer Gisborne	$ 1,500,000				
Option 3rd 110kV Line from Tuai	$ 15,000,000				
Option 3rd 50kV Subtransmission ring	$ 4,000,000				
Option New GXP Patutahi	$ 6,500,000				
Option Replace GXP Massey Rd Gisborne	$ 8,500,000				
Option Base load Generation	$ 8,500,000				
Mahia 33kV line extension and Substation	$ 1,520,000				$ 1,520,000
Waihi 33kV Rationalization	$ 1,500,000				
Affco /Wairoa CBD supply capacity upgrade and 33kV Line	$ 1,500,000				
Tuai Wairoa 11kV line interconnection Frasertown Feeder	$ 425,000				

7.0 RISK MANAGEMENT

ENLs risk management process is intended to assess its risk exposure and prioritise mitigating actions.

The process is as follows:

- Risk issues are identified and recorded.
- Minor risk issues are eliminated or controlled.
- Potential solutions/actions are developed.
- Actions are assessed against outcomes or success factors.
- Actions are ranked on the basis of weighted performance against outcomes.
- Results are then applied to cost benefit analysis in project viability tests.

This approach overcomes difficulties in trying to quantify risk via assessment of frequency, severity and impact.

General Policies

ENL at all times endeavours to purchase and provide secure risk managed products and services at the least cost and at the same time if possible secure long term contracts for purchases, services and sales.

Only authorised Contractors and Personnel may transact business in the Company's name and specified limits shall be maintained for such authorisations.

ENL is only to purchase or sell product or services in line with its business expertise

ENL will only undertake transactions with approved contractors and suppliers. Such transactions shall be maintained within specified limits.

The Risk Management Policy and related procedures and systems are to be reviewed 2 yearly by an independent party.

Annual internal reviews of risk management documentation are undertaken to ensure risks have been assessed correctly and that actions to reduce risks are identified and reviewed.

Note: A more comprehensive Risk Management Plan is presently under preparation as part of a full review of EIL's risk management processes. The review and action plans are scheduled for completion in July 2004.

Risk Categories

ENL uses the following tactics to manage risk: under the following categories;

Business Risk

Land Use – Legal agreements and Easements are maintained for all sites considered strategic or land use/access that is vulnerable to dispute.

Customer closure – Regular communication is maintained will all significant customers receiving line services from ENL. In addition to growth projects ENL have in place policies to provide assistance to local businesses.

Documentation – Quality system procedures are in place for storage /duplication of critical documentation. A majority of the critical documentation is backed up via the computer systems used to generate the documents. Risk of total loss is controlled by use of multiple storage locations throughout the region.

Information systems – IT procedures are in place to provide 100% redundancy and backup for all systems used. Spares are maintained for critical equipment items. Testing of procedures and auditing of their effectiveness is undertaken on a regular basis.

Competition - Assessments of these risks are undertaken annually as part of ENL's strategic planning process. As issues arise they are discussed at monthly Board meetings.

Communications – Alternative communications systems are maintained. Use of external service providers is duplicated by ENL's own communications network. (Refer section 8A.14)

ENL maintains the ability to Relay business communications via Third parties based outside of the Gisborne and Wairoa regions.

Security- Security provisions are maintained at all strategic sites. Long-term contracts are in place with security providers. Security systems are tested annually. Quality system procedures for financial authorities and identification of ENL representatives are in place and are externally reviewed.

Confidentially- Policies and Quality system procedures are in place to control the associated risks.

Legal Compliance/Statutory liability. - Quality system procedures and 6 monthly check lists are used to ensure all obligations are met on time and to ensure issues are identified and resolved. Issues are reviewed at 6 monthly board meetings and external parties are used for procedural reviews.

Project Management and Professional Liability- Regular training and refreshers are carried out. Insurance policies and registrations with professional bodies are kept up to date. Contracts with service providers define provisions required to control associated risks. Maintenance and inspection activities (refer section 8) documented in this plan, in addition to condition assessment information target identification of hazards and non-compliance issues. Targets for elimination of the risks associated with the hazards and compliance issues are also documented for each asset category in section 8 of this plan.

Financial-Contracts with retailers define liability and performance penalties. Contracts with suppliers include requirements for insurance and protection of works.

Health and Safety-Quality system policies, procedures and 6 monthly refresher training are in place. These procedures include Hazard identification and control, Contractor authorisation, Incident reporting and standards for conduct. Self-auditing and Independent auditing requirements are included in contractual arrangements and Network authorisations

Emergency Response

ENL maintains an emergency preparedness plan which provides procedures and contact lists for Explosion, Fire, Disease, Accident/injury/death incidents and environmental accidents, that may be associated with operation of its main office facilities, Network facilities / Assets and incidents involving contractors to the company.

Disaster Recovery

Policies plans and readily accessible documentation is maintained to maximise the effectiveness of ENL's effort in overcoming Disaster events. Financial arrangements and insurance policies are in place to control the associated financial impacts resulting from events of this nature. The network is covered by catastrophe insurance. Annual budgeting includes a contingency sum for storm and large unplanned events.

Events considered in the assessments include Flooding, Earthquake, Tsunami, War, Landslips, Drought, Volcanic Eruption, Severe Storms and Bush Fire

Electricity Supply

Loss of Bulk supply- Transpower does not include N-1 level security within contractual arrangements at the Gisborne and Wairoa Grid exit points. Hence there is no ability to negotiate cost penalties for loss of supply as was experienced in 2001/2002 and 2003. The purchase of six 1MW diesel generators in 2003, when combined with the Waihi hydro scheme has provided ENL with demand Generation capability up to 20% of the maximum demand.

Liability for loss of supply or fluctuations- Contractual arrangements and insurance policies are in place to control the associated outcomes.

Revenue Protection- Procedures are in place to work with Energy retailers where necessary to continually monitor identify and eliminate issues.

Electricity Outages

Breakdown and Equipment failure:

Network Design and material standards are used to control the quality and suitability of product used. Procedures for documentation of asset \ equipment failure are in place. Suitability of new product and product used is the responsibility of the Asset Manager and is under continual review. Significant risks identified are included for each asset category in section 8 of this plan. Asset based solutions and standards detailed specifically for each asset. Strategic spares of critical items with long delivery times are held by ENL including 50kV/11kV transformers 50kV switchgear/line hardware, Protection/SCADA and communications equipment. Equipment that can be relocated to cover failure of strategic items has also been identified. Generally this includes 50/11kV transformers, and down stream 11kV switchgear and protection equipment that can be used to replace failure of primary feeder circuit breakers and protection.

Supply restoration:
Contracts provide for minimum resourcing, backup resourcing, and response practices. Response Plans include pre-prepared switching and contingency plans for all sub-transmission and critical equipment. Product suppliers are monitored and audited to ensure specified minimum levels of product spares and replacements are maintained in the region. Procedures and documentation are maintained to ensure product can be sourced from outside the region in a timely manner to cater for catastrophic events. Re-locatable diesel generation is available as a substitute for normal distribution supply. Procedures are in place for review of outages to identify issues where security standards are not maintained in terms of redundant capacity, alternative supply options and restoration times. Corrective actions are incorporated into contractual arrangements design standards and asset management plans as appropriate to control the risks.

Access / specialised equipment issues:
Procedures and arrangements to ensure 24 hour access to specialised equipment are maintained and verified on an annual basis.
Competency and capabilities in Helicopter transportation and line reconstruction techniques are maintained to ensure risks associated with road access are controlled via alternative means. This is particularly important in remote areas of the region.

The results for identified risk issues directly relating to asset management risk assessments and action plan priorities are presented in Section 6.2. Specific risk issues, contingencies and actions are identified for each asset category in Section 8.0 of this AMP.

8.0 LIFE CYCLE MANAGEMENT

Life cycle management plans outline exactly what is planned to manage and operate the assets at the target levels of service while optimizing lifecycle costs. This section includes detailed capital and maintenance action plans, presented separately to clearly distinguish between the expenditure and actions related to each.

Each asset category is presented separately with background information provided on physical parameters, capacity and performance, condition and age profiles, valuation, and historical treatment. This data is used as the basis for decisions on optimized renewal/replacement, new acquisitions or augmentation, routine maintenance and disposal.

Alternatives and options available are discussed throughout the individual asset plans.

8.1 The Asset Life Cycle

An assets life cycle starts with planning its necessity, continuing through design, investment, operation and maintenance, and concluding with replacement and/or disposal. Life cycle asset management encompasses the policies and practices applied during all phases of an assets life to ensure the sustainable delivery of a power supply in the most efficient manner. Standards and requirements may change during the life of an asset.

The physical life of an asset is the time an asset will deliver the service level it was designed to. Its life expectation will fit a predictable distribution that only changes if design conditions and assumptions change.

Economic life is dependent on an asset remaining “fit for purpose”. Over its physical life an asset may become obsolescent, the revenue it generates may decline due to a drop in demand, standards may increase beyond its ability to deliver, changing practice may alter the economics of increased maintenance versus replacement. These factors may reduce the economic life relative to physical life.

8.2 Age Profiles

Historically there has been little need to consider when an assets life has finished because replacement was occurring through growth demands. Installation of new asset is now low and so the installed asset base is ageing. As this happens, performance decreases and costs increase to a point where it is no longer economic to continue maintaining assets.

By analysing the age profile of assets their life expectancy and the characteristics of their failure can be determined.

This Plan uses age profile where possible to predict:

- the ageing characteristics of assets
- the end of economic life, and

- the amount to be targeted for replacement and maintenance.

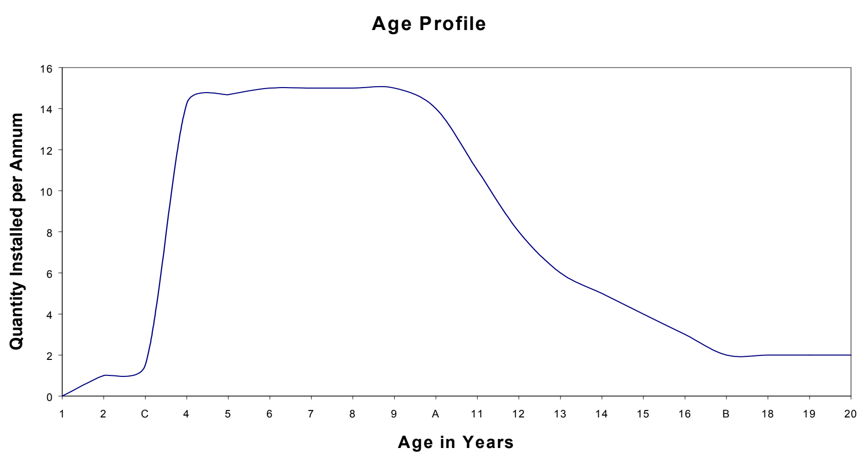
The ODV has been used to provide a default life where age profile data is inadequate due to short installation period, small population, or insufficient age history.

Assets should be replaced at a time that best satisfies the following considerations:

- Before increasing maintenance costs become excessive.
- Before reliability becomes unacceptable.
- To take advantage of technology improvements.
- To improve operational efficiency.
- To provide added value services to customers.

The rate at which assets are replaced should aim to smooth expenditure peaks that arise in the age profile due to installation patterns, i.e. don't want growth patterns from the past driving today's investment decisions.

Consider a typical age profile (Fig 8.1):



The curve shown has been smoothed out for normal annual variances in installed quantity that would be seen on actual age profiles. Most profiles where the history is long and stable enough show this trend in their age profile.

The start of the curve represents the low installation period currently being experienced. During this period minimal replacements or new installation has occurred. Installation is not occurring because of growth or because of asset age.

The period during which most of the existing asset was installed is represented by the flat centre section. It is flat only where growth is constant and actual curves may show a number of peaks. During this period there is a low attrition due to asset ageing i.e. most of the installed quantity is new asset. In this period there is minimal requirement to maintain the asset.

At some point the survival rate of the asset drops and the age profile shows a roll off in installed quantity. An increasing amount of asset requires repair or renewal. During this period reliability falls and maintenance levels rise. The duration of this roll-off period represents the effectiveness of maintenance in extending asset life and also how consistently or predictably an asset fails. The quantity reduces, as asset has to be replaced i.e. as it reaches the end of its economic life.

The roll-off then flattens off to a residual quantity of installed asset. This quantity represents asset that has had its life extended well beyond normal expectations because of some history of major maintenance or reconstruction beyond that required to keep the asset operational. Where maintenance has occurred in the otherwise maintenance free period the life is extended. The relatively minor quantity of asset remaining as a result of this work indicates that this is an inefficient maintenance method. Using a condition driven maintenance programme this residual quantity should gradually reduce, as the need for maintenance must be proven.

8.3 Renewal Decision Making

The following process is applied:

1. From asset data a population age profile is produced.

2. The age profile is normalised and smoothed. The survival curve is then fitted to the age profile. This creates a model of the assets physical life cycle. If no age data is available then an industry-derived model is assumed. ODV life is applied as the default. During normalisation, curve fitting currently applies engineering judgement and specific company and asset knowledge and not standard numerical methods.

3. The rate of failure is determined from the survival curve. A binomial distribution can be applied to determine the probabilities of early or late failure in service.

4. This distribution can then be applied to each year’s population installed in a given year, to develop a probability density function for the entire population. Hence the number of expected failures can be predicted in any one year. This level of accuracy is only required when a population is approaching its asset life or into its failure period.

5. Assessment of residual surviving assets can be used to determine the effectiveness of heavy maintenance, with replacement quantities discounted.

6. Replacement can be spread and costs smoothed by determining which assets are critical and require early replacement, and which are not critical and can risk in-service failure. Assessment of criticality requires judgement of the level of risk associated with failure of an asset in service, including the following factors:

   - Duration of outage
   - Cost of damage repair
   - Economic impact on affected consumers

- Secondary effects, e.g. loss of other utilities

7. Replacement quantities are adjusted to address issues of economics, compliance, growth, and management tactics.

8.4 Capital Replacement vs. Maintenance – An Example

The following discussion uses 11kV pole line data as an example of the process used to determine the point at which it is more economic to undertake capital replacement of assets than to continue with a regime of continuous replacement via heavy maintenance. 11kV lines represent the bulk of ENL's assets and therefore their replacement dominates capital expenditure programmes.

The two main components to power lines are poles and conductor. Poles represent 60% of the capital cost of a new line. Poles can be repaired and maintained but have a service life of typically 50 years. Their failure rate is centred around 50 years and has a bell shaped distribution extending approximately 10 years either side. Maintenance skews the distribution towards longer life. Most assets follow this pattern. The age profile is used to determine the mid-point, the range either side, and the probability of failure. Distortions have to be normalised to remove variance in installation programmes, maintenance regimes, design, etc.

A new line has very few failures for the first 30 years of service. After 40 years a sharp knee is seen with failure rapidly increasing. Eventually the level of replacement has reached the point where sufficient new poles are in the population to see a decline in the failure rate. However a second cycle of failure starts as poles replaced early begin to fail. Their distribution of failure is more spread out, smoothing the curve. After several cycles, replacement is required at a virtually constant rate.

Once the failure rate is determined the cost of maintaining poles can be calculated using data that reflects actual costs of current maintenance practices. ENL's maintenance programme starts with condition assessment. New poles do not require inspection at the same frequency as older poles. The incidence of minor defect repairs e.g. crossarms, follows the inspection programmes that identify the defects. Once poles are condemned they can be repaired, replaced or left to fail and then replaced in fault conditions. Actual figures indicate that our 5 year average is a 34% planned replacement rate and 8% repair. Planned replacement is more cost effective than unplanned and repair is only undertaken if pole condition warrants it.

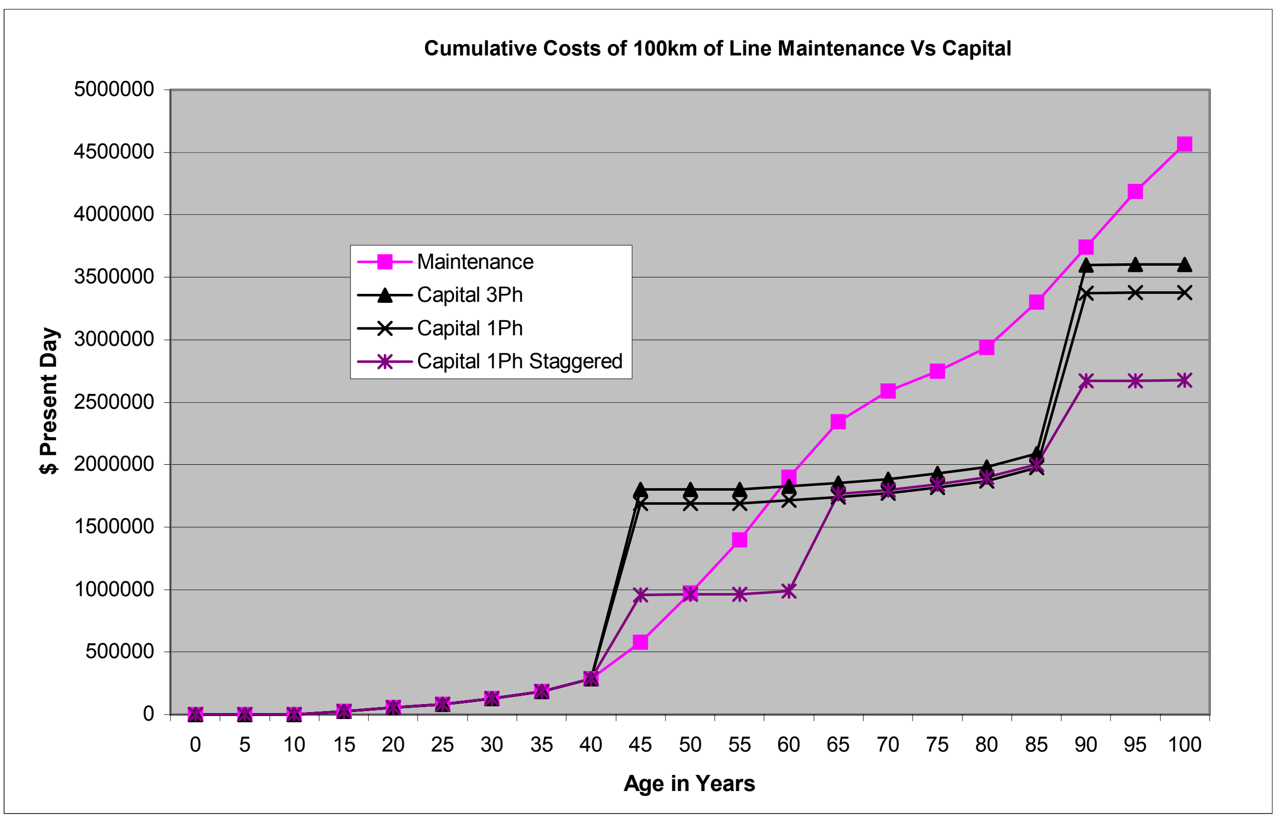
Conductor cannot be repaired. Once it reaches a certain condition it has to be replaced. The life of conductor is approximately 65 years with a range of 50 - 75 years. Adding these costs, a total maintenance curve can be derived and this is shown Fig 8.2. The curve has a sharp knee at 40 years where costs start to climb rapidly. After two life cycles this high expenditure is being sustained at an almost constant rate.

If the 40-year knee is used as the optimum point for capital replacement a stepped curve is created. This curve is only marginally lower cost, (but still worthwhile) on an annual basis, compared to much smoother maintenance expenditure, when the present value of funding the large capital steps is factored in. The big difference is that at the point where the same level of expenditure has been spent on maintenance, only 75% of the line has been renewed, where as it is all 15 years old under the capital regime. An additional curve is shown to demonstrate the type of effect that replacement with cheaper single-phase design might realise. Other considerations are size and efficiency of the organisation needed to administrate a maintenance approach compared to the significantly smaller organisation required to let replacement contracts and operate a network too new to fault.

The fourth curve has been derived by, maximising the benefit that can be gained from the fact that conductor lasts 20 years longer than poles on average. The knee for conductor replacement occurs at 60 years. At 60 years 20% of poles can be expected to have survived. Therefore this curve assumes 80% of the worst poles are replaced at 40 years and the remaining 20% are replaced at 60 years when the conductor is renewed. The resulting curve has much more readily managed capital steps and results in an average gradient much lower than the maintenance curve. Therefore this is the best option.

ENL's oldest lines tend to be in uneconomic areas. Replacement affords the opportunity to apply alternative low cost solutions possible for these areas. Therefore cost savings are enhanced, as we are not trying to perpetuate an uneconomic solution. This is better in the long run for ENL, our customers, and the local economy.

A similar process can be applied to other assets to derive their targets.



8.0A CAPITAL

The capital section of the life-cycle management plan presents the background data and plans for renewal, replacement and augmentation in response to asset aging, growth, reliability, performance, compliance and quality issues. Non-asset solutions are also presented where appropriate.

8.A.1 50kV Overhead Lines

DESCRIPTION

Configuration

ENL has no underground asset at this voltage. Rural areas are predominantly wooden pole with preservation bandage fitted and flat construction with wooden crossarms fitted with pin and post insulators. Urban areas are predominantly concrete pole with delta construction and no cross arms. Where crossarms are necessary, steel arms are standard. Rural areas use Dog conductor as standard (low implementation) while urban areas use Cockroach conductor as standard (high implementation).

Location

The 50kV network has several sections.

(i) A single rural ring circuit from Gisborne via Hexton switching station to Puha, Ngatapa, Pehiri, Patutahi, Makaraka and back to Gisborne. A line was constructed between Hexton switching station and Makaraka in 2001 to provide for increased capacity on the 50kV bus at Makaraka. The section from Patutahi to Makaraka and Makaraka to Gisborne sub was built by PBEPB for NZED in 1950. This has been in ENL's ownership since 1958. The section from Gisborne to Puha was constructed in 1959 using reused insulators and conductor recovered from NZED when the new 110kV tower line from Tuai was commissioned. In 2003 the sections of line from Gisborne to Hexton and Makaraka were re-conductored with Cockroach conductor. The remainder of the loop was constructed between 1960 and 1972. A single spur line constructed at 50kV and operated at 11kV tees off between the Puha and Ngatapa segment of the rural ring and runs to Matawai.

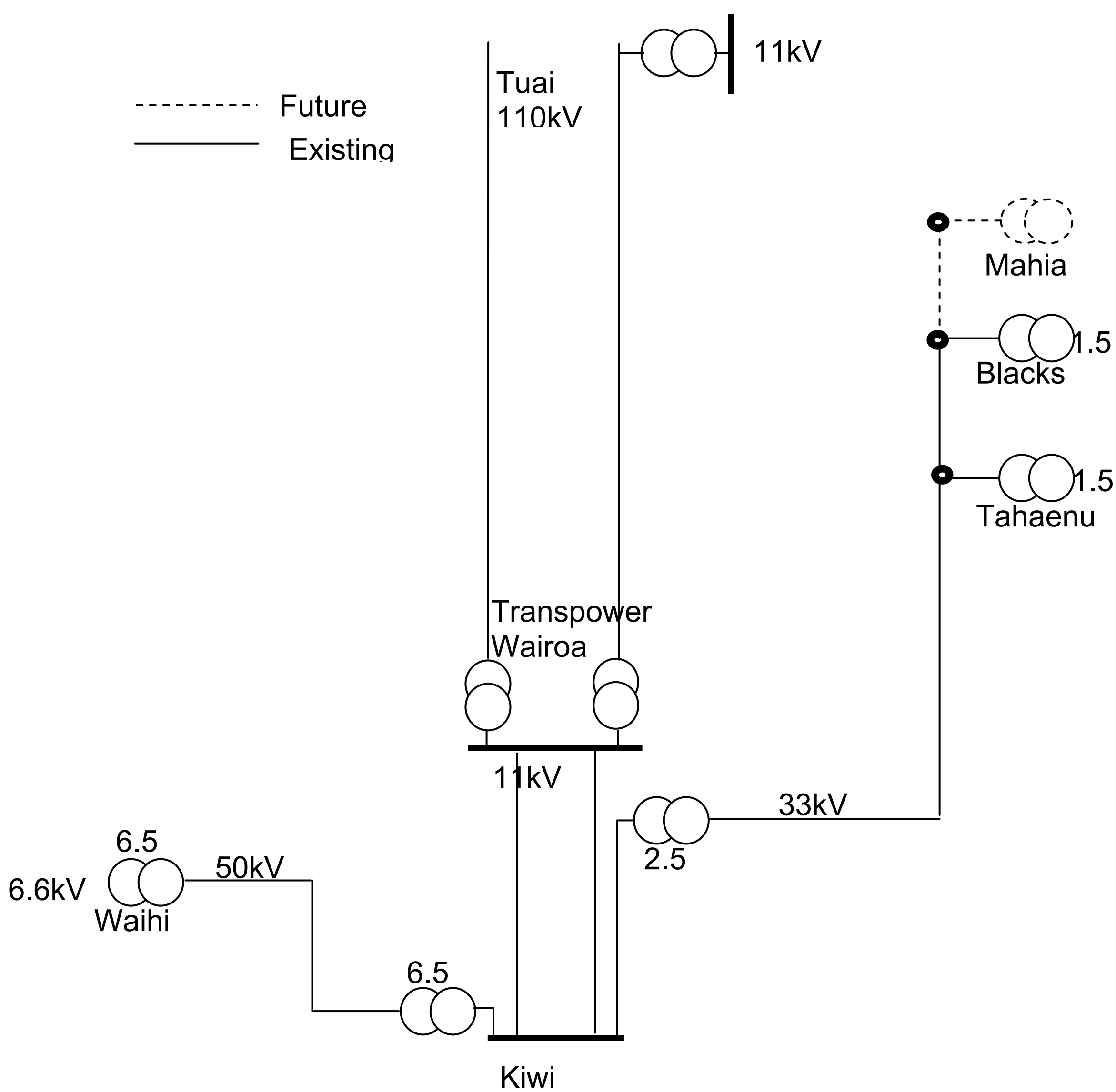
(ii) A single 50kV spur extends up the coast from Gisborne Sub to Tolaga, Tokomaru, Ruatoria, and Te Araroa. The section from Gisborne to Tokomaru was constructed in 1955 by NZED. Ownership was then transferred to ENL when the 110kV NZED line to Tokomaru was constructed between 1978-1980. The line from Tokomaru to Ruatoria was constructed in 1964 and on to Te Araroa in 1971.

(iii) Lines to the urban Kaiti, Parkinson and Carnarvon Zone substations were built between 1971-1987. Kaiti and Carnarvon are fed via spurs from Gisborne Sub. Carnarvon Street has a second 50kV supply via a Tee connection to Parkinson Street which is operated as an open ring. Parkinson Street line connects to Makaraka. The line between Makaraka and Matawhero was constructed in 2000. The line between Kaiti and the Port was added in 2003.

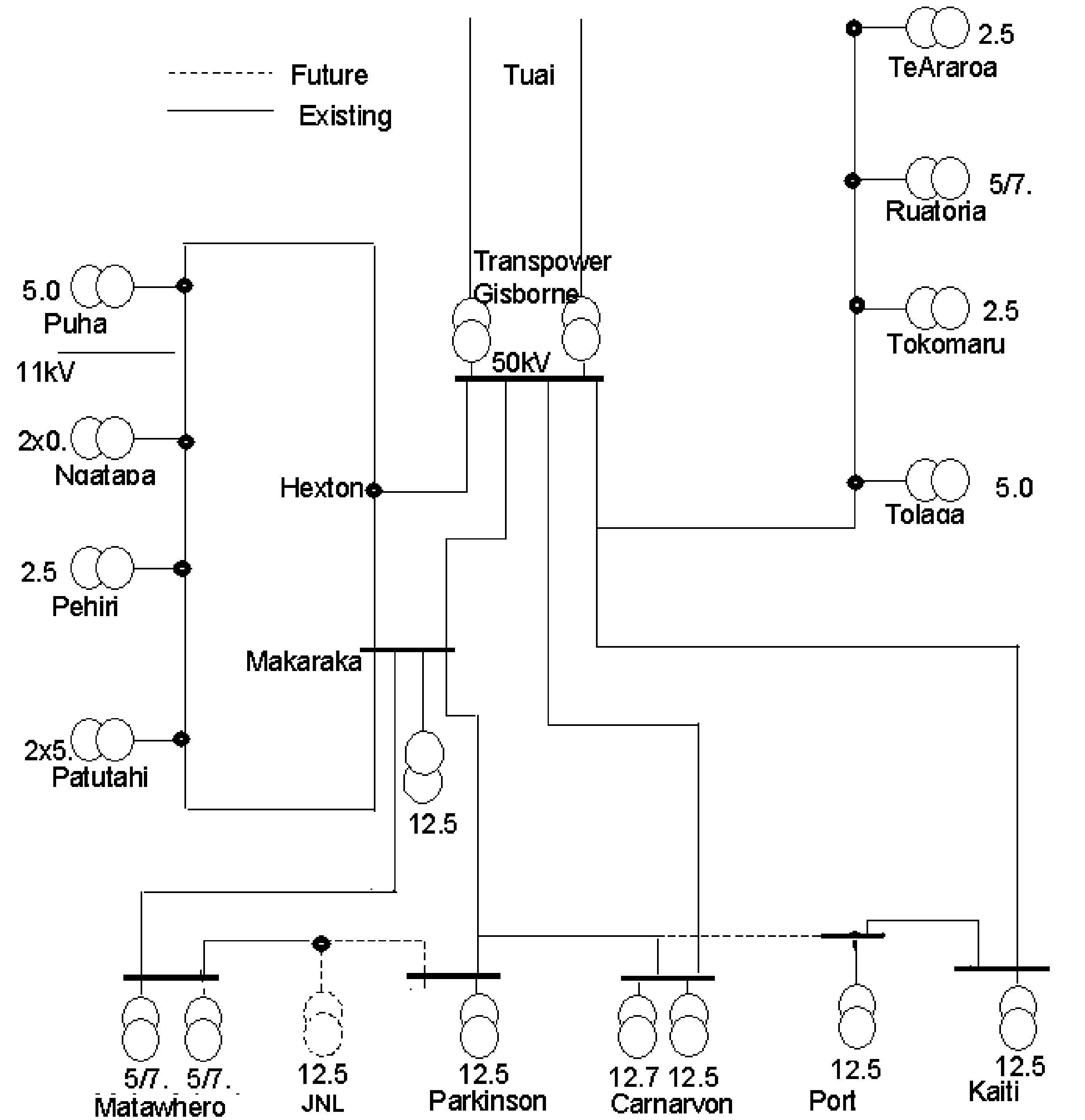
(iv) The Mahia Peninsula was originally supplied at 50kV from Wairoa and was converted to 33kV in 2000. This line is insulated at 33kV in sections and as such was experiencing poor reliability up until 2000. This line has Chevron construction. The line length is 35.4km and a majority of the poles are wood.

(v) The Waihi generation scheme injects into the Wairoa network via a 50kV line to Kiwi substation. Poles are shared with Network 11kV under-built circuit in parts. The length of line is 40km and a majority of the poles are concrete.

Single Line Schematic (Wairoa)

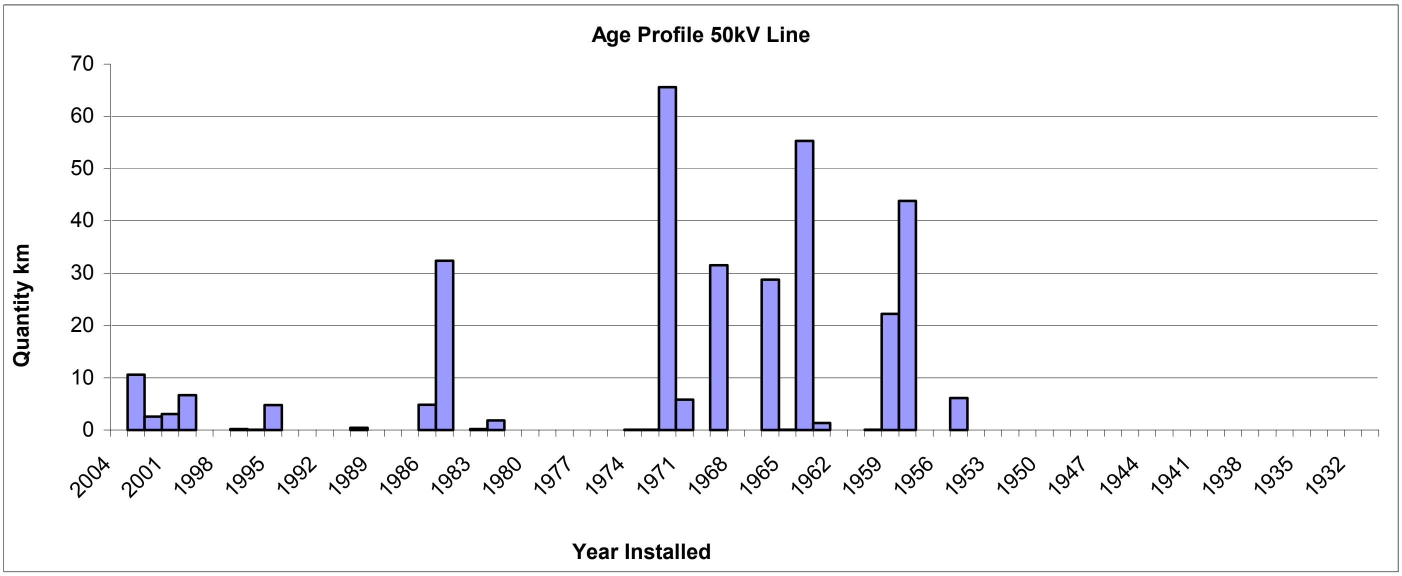


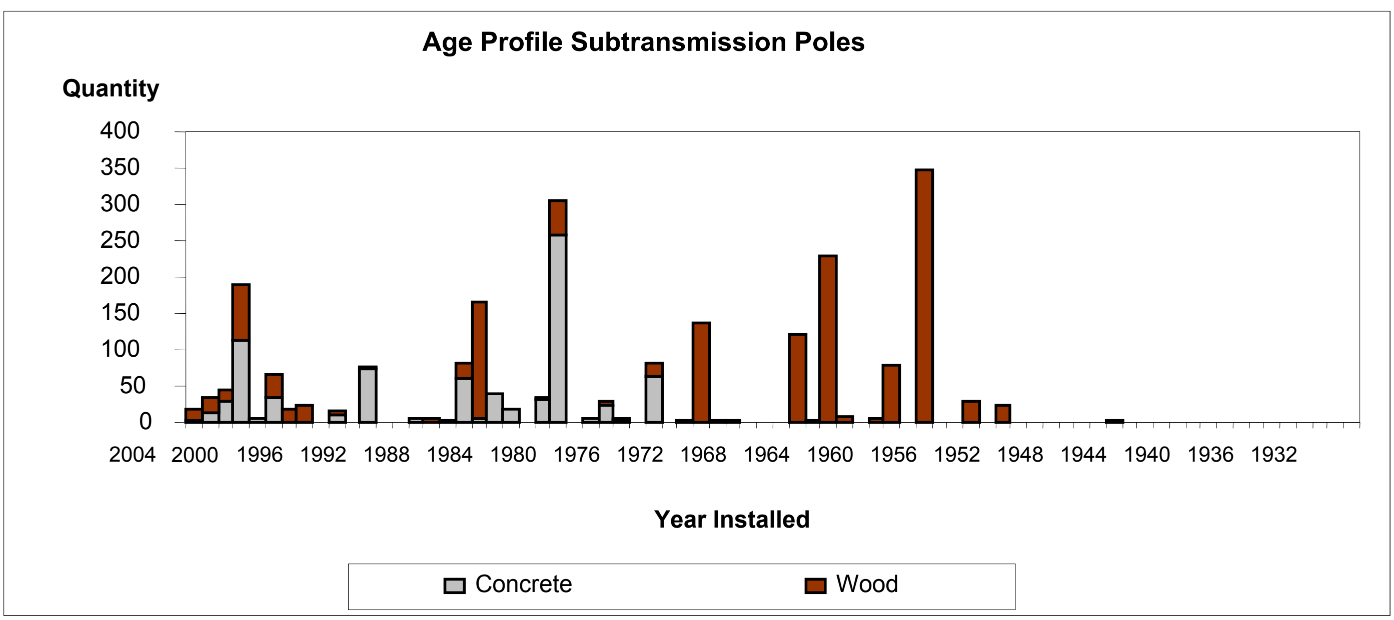
Single Line Schematic (Gisborne)



LIFE ASSESSMENT

ODV Standard Life (Wood/Concrete)	45/60 years
Population Size	2441 poles – 327km line
Steady state replacement rate	46 poles - 5km line
Start of failure period	44 years
Failure period	4 years
Average residual quantity	10 poles
Targeted replacement rate	40 poles - 0km line
Rate of growth additions	20 poles - 3km line





Age Profile Comments

- Conductor is lasting longer than poles in terms of condition however Growth and Security triggers have prompted conductor size increases. Poles are well into their age replacement period while conductor is predominantly showing the initial installation pattern. Note some conductor is second hand, explaining the less smooth and more spread installation profile.
- Poles in replacement zone are wooden.
- Critical asset demands replacement before the in service failure rate becomes high.
- The replacement rate for poles from 1988 indicates age replacement cycle already in progress.
- The high growth period between 2003 and 2005 is associated with urban reinforcement.

PLANNED REPLACEMENT PROGRAMME

Replacement Criteria

In addition to the criteria identified by condition assessment, an entire section of line will be replaced as capital renewal if the total required maintenance expenditure exceeds 20% of the cost of new asset, i.e. for 50kV lines at $70,000/km the ceiling for maintenance expenditure is $14,000/km. This will include conductor renewal if existing conductor has less than 5 years remaining life.

Summary of Actions

- Replace 40 poles per year steady state. $240,000 from 2005/2006.
- Age replacement for conductor assumes 75 year life hence no planned replacement is currently undertaken. Conductor replacement undertaken currently is linked to growth and security undertakings.

GROWTH

Constraints and Triggers

ENL's standard 50kV line construction in urban areas uses Cockroach conductor giving a capacity of 30MW. The need for 50kV lines is driven by substation size and location. Capacity and security provisions are co-ordinated at 50kV line, substation, and 11kV inter-connection.

Forecasts

Forecast upgrades are derived in the Security Review and Network Development Plan sections.

Summary of Actions

Year	*Action*
2004/2005	Port-Carnarvon 50kV
2004/2005	Parkinson-Matawhero 50kV
2005/2006	33kV extension to Mahia

Pricing incorporated in network development plan

RELIABILITY AND SERVICE

Standard

The standard to be targeted is nil failures due to pole, conductor and hardware failure that can be prevented through active management.

Justification

The sub transmission system forms the backbone of the network and determines the underlying level of performance. Very large numbers are affected during outages therefore more intense management of condition is justified.

Criticality

This asset is critical to reliability and therefore replacement programs should aim to renew asset before failure in service.

Gap Analysis

COMPONENT	ACHIEVED REPLACEMENT RATE	ACTUAL FAILURES P.A	REQUIRED REPLACEMENT RATE
Poles	40	0	40
Conductor	-	0	0
Binder	5	0	106
Insulators	30	10	30
Crossarms	5	2	5
Trees	na	4	na
Animals	na	2	na
Vehicles	na	1	na

Summary of Actions

Due to criticality of this asset any known defects are to be dealt with within a year. If components are still failing in service, or the backlog of defects is increasing, then the planned replacement rate will be increased.

PERFORMANCE ISSUES

Component Failures

Despite some conductor being very old, there are no identified corrosion or strength issues predicted. Some vibration damage has been identified during inspections. Conductor and bindings are repaired and vibration clamps are fitted as identified. A test instrument is used to confirm presence of vibration, which is initially picked up by visual inspection of binders.
Glazing is failing on OB insulations. This is believed to be the result of age, agricultural chemical and sun damage. It results in TV interference complaints, which we are obligated to repair in an acceptable time frame. This is more expensive than a co-ordinating replacement with other planned work. Discharge detection cameras are also used to identify problem sites with all 50kV lines checked 2 yearly. Approximately 5 sites p.a. are identified and corrected.

There is known problem of pole fires caused by failures NGK 10 skirt insulators. These are only rated at 45kV and problem is more prevalent in areas close to the coast. It is estimated that approximately 500 insulators of this type are still located in the problem area. Between 2000 and 2003 approximately 20 insulators p.a. were replaced. No allowance is made for replacement until problem sites are identified.

There are approximately 750 strings of blue and brown ceramic insulators that are in the order of 80 years old. These insulators were received in 1960, 2nd hand from NZED. Industry experience indicates that we cannot expect much life out of insulators and we should plan for their replacement over the next 15 years

The above information indicates that ENL should plan for the replacement of 30-pole sets p.a. This work is to be co-ordinated with other defects and assessment of total structure replacement. Replacement cost is approximately $2000 per set of 3.

The original suspension strings on the Mahia Line were discovered to have severe wearing on the top hook (40% worn through) in 2001. They had also been stressed through incorrect operating voltage (corrected in 2000). A majority of these insulators were replaced between 2001 and 2003. The Mahia line has no armour rods fitted to protect the conductor which may shorten conductor life. Remaining problems will be addressed as identified.

When Neutral-earthing Resistors are added at the Gisborne 110/50kV supply point, refer development plan, 50kV insulator coordination will need to be reviewed as NER's will permit 100% line to line voltage to appear on un-faulted phases during earth faults. Old insulators rated at 45kV may not prove adequate. The 50kV surge arrestors have been reviewed and 2 sets require replacement to coordinate operation with NER's.

Component replacement following inspection rounds is allowed for at $40,000p.a.

All other hardware is believed to be in adequate condition to survive the pole.

Summary of Actions

OB Insulator Replacement	$30,000 p.a.	
NZED 2nd hand Insulator replacement	$30,000 p.a.	
Other insulator replacement	as identified	
Component replacement allowance	$40,000 p.a.	
Surge arrestor replacement Gisborne 50kV	$30,000 p.a.	2004-2006

COMPLIANCE ISSUES

Monitoring

The main compliance issue associated with 50kV lines is pole strength. The condition assessment process identifies and forms the basis for managing poles by calculating the safety factor in terms of remaining pole strength and required design strength. Poles found with deterioration compared with initial strength can then be prioritised by assessing the benefit of arresting rot. The adequacy of remaining strength compared with original design strength is also taken into account. Using design strength modelling tools, the optimum method of reinforcing deteriorated poles verses replacement can be determined. The same tools are applied to new structures to ensure engineering standards are complied with. The secondary compliance issue relates to the ability of the pole to support its fittings securely. ie. Split pole heads.

Standard

Following inspection pole safety factors are recalculated. Where poles are found in terms of remaining strength verses design load, to have a safety factor less than 1 or pole head damage is of a critical nature, suitable reinforcement/repair or replacement actions are scheduled within 3 months. Actions are prioritised depending condition and criticality. Refer Condition Assessment Standards.

Gap Analysis

50kV poles receive priority treatment; therefore no gap exists between compliance outcome and the management practice applied to achieving that outcome.

Required Outcome

Nil failures.

QUALITY AND DEVELOPMENT

Standardisation

Construction of new or replacement asset will adhere to following standards:

- Concrete poles (unless limited by weight for helicopter installations)
- Cross-armless delta configuration, and cross-armless angles for live line compatibility

- If phase separation dictates use of crossarms, then steel arms with flat post insulator construction are used
- Polymer strain insulators – no strings
- No LT under building
- Avoid main highway line routes
- Standard conductors: Cockroach – urban, Dog – rural
- All poles to be fitted with possum guard
- Line make-offs/staying approximately every 12th pole if there are no intermediate make-offs or angles
- Conductor spacing and insulation to minimum 66kV standard

New Technology

All technology improvements relate to standardisation of components and the application of computer aided design.

Amenity Improvements

Delta construction with no crossarms presents better visual amenity.
The no LT under building standard is intended to reduce risk and limit damage resulting from high to low voltage clash and induction during faults.

NON-ASSET SOLUTIONS

No planned reduction in service or divestment of asset is planned for the sub transmission system as it is core and merits total average costing across the entire asset/customer base.

The Matawai line will continue to operate at 11kV indefinitely.

The Wairoa sub-transmission network will be rationalised to 33kV.

8.A.2 11kV Overhead Lines and Underground Cables

DESCRIPTION

Configuration

ENL has both overhead and underground asset at this voltage. Rural areas are predominantly wooden pole, flat construction with wooden crossarms and pin insulators. Urban areas are predominantly concrete pole with wooden crossarm construction. Cable network is concentrated in the CBD and newer subdivisions.

Description	Length km
Overhead 3 Phase	2,362
Overhead 1 Phase	92
Underground	104
Total	2558

Location

The 11 kV network extends from Lottin Point at the East Cape to Raupanga along the East coast. From Gisborne the network extends inland to the Matawai and Motu area and from Wairoa the Network extends to Lake Waikaremoana.

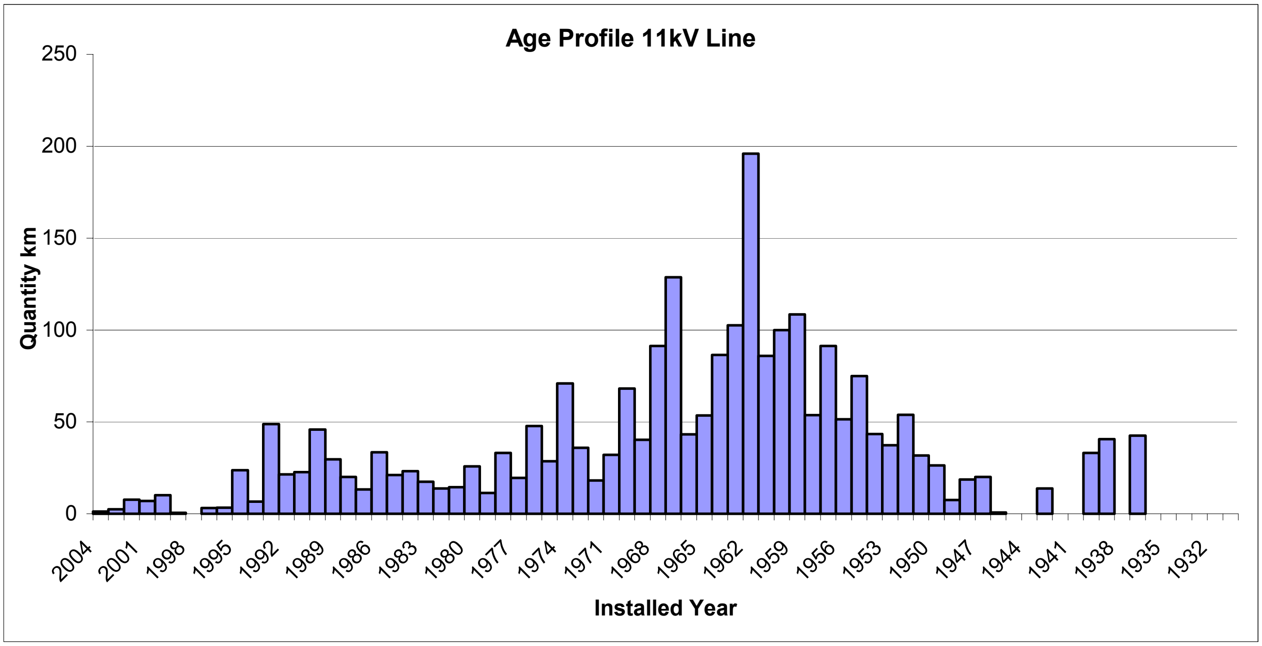
A summary of overhead line quantities is shown in the following tables:

Location	**Terrain**	**Total Length km**
Within 75km of Gisborne	Normal Terrain	859
Within 75km of Gisborne	Rugged Terrain	586
Within 75km of Gisborne	Road Side	471
Remote	Normal Terrain	216
Remote	Rugged Terrain	232
Remote	Road Side	87
Zone Substation Breakdown	**Average Span Length m**	**Total Length km**
- TeAraroa	102	124
- Ruatoria	82	180
- Tokomaru Bay	92	174
- Tolaga Bay	94	164
- Kaiti	71	116
- Carnarvon	35	8
- Parkinson	47	12
- Makaraka	69	124
- Patutahi	70	238
- Pehiri	105	139
- Ngatapa	96	107
- Puha	97	349
- Matawhero	59	22
- Port	55	2
- Tuai	159	116
- Wairoa	115	439
- Blacks Pad	114	87
- Tahaenui	101	53
Average Feeder Length		38km

LIFE ASSESSMENT (Lines)

ODV Standard Life	60 years
Population size	2454km
Start of failure period	1959 - 49years
Failure period	10years
Average Residual Quantity	30km
Average Installation Quantity	40km

Targeted Replacement Rate 20km
Rate of Growth Additions /Upgrades 7km



The installed 11 kV conductors consist of aluminium (22%), steel (27%) and copper (51%) construction.

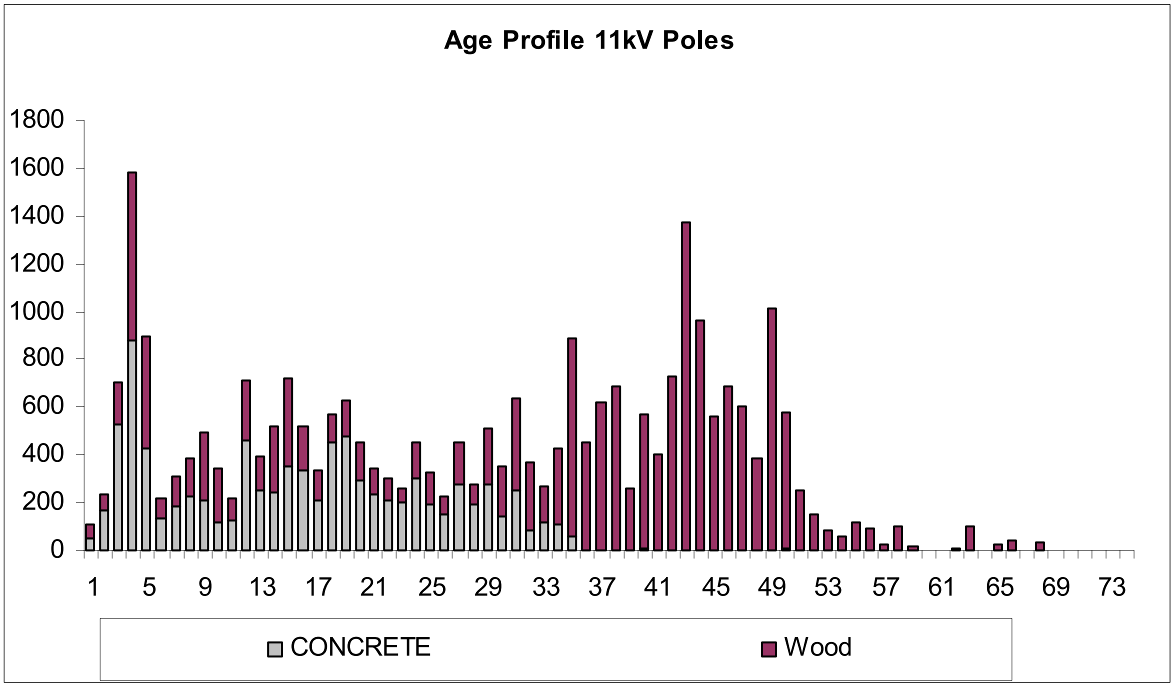
Age Profile Comments

- 78% of the conductor used is copper or steel. The conductor size is typically small due to lack of capacity upgrading.
- The line population is older than the pole population, which is reflected in condition.
- The 60-year life represents the end of the age failure period not the start.
- Circuits of higher importance closer to major load need to be prioritised for replacement. ie Tie feeders should have replacement programs starting at 50 years.
- Approximately 30% of conductor is in the age failure portion of the life cycle.
- Divestment in remote areas and planned upgrade work significantly reduces the replacement target.
- The pole replacement program has uncovered a high incidence of broken conductor strands under bindings due to fatigue on light copper lines. This is also evident in the fault statistics.

LIFE ASSESSMENT (Poles)

ODV Standard Life	45/60years
Population size	8500 Concrete & 18356 Wood
Start of failure period	42years
Failure period	10 years
Average Residual Quantity	100
Average Installation Quantity	600

Targeted Replacement Rate	450
Rate of Growth Additions/ Upgrades	50

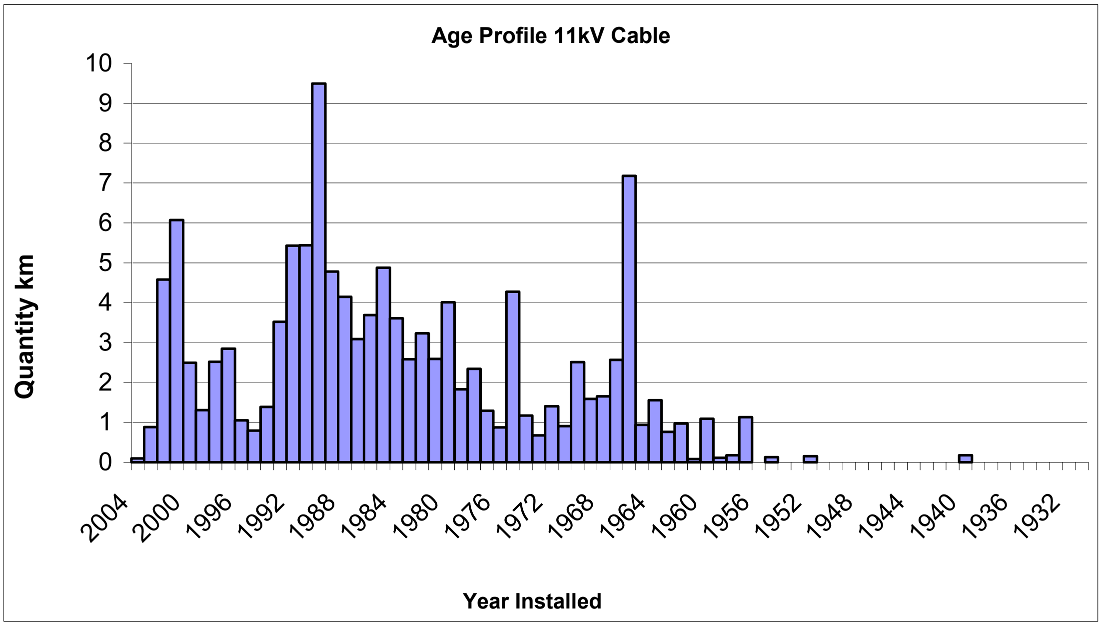


Age Profile Comments

- Well into age replacement program (driven by compliance).
- Close to steady state replacement rates being realised from 2001.

LIFE ASSESSMENT (Cables)

ODV Standard Life	45-70 years
Population size	122km
Start of failure period	50 years
Failure period	15 years
Average Residual Quantity	0
Average Installation Quantity	2km
Targeted Replacement Rate	0
Rate of Growth Additions\ Upgrades	2km



Age Profile Comments

- Due to sample size and relative new age of asset profile showing mostly installation pattern.
- Capacity upgrades sufficient to mitigate age replacement.

Data Source

ENL's own model adjusted from experience and improved data from inspection.

PLANNED REPLACEMENT PROGRAMME

Replacement Criteria

An entire section of line will be replaced as capital renewal if the total required maintenance expenditure exceeds 20% of the cost of new asset, i.e. at $70,000/km the ceiling for maintenance expenditure is $14,000/km. This includes conductor renewal and costs reflect replacement of existing asset not new construction.

Lines

Conductor requires replacement at a rate of 40km per annum. Currently ENL is targeting replacement of 20km p.a. at $30,000 per km. This difference between required and targeted replacement is due to ENL's strategy for uneconomic lines, Refer 6.5.2, underground replacement strategies in urban areas. Total cost p.a $600,000. Areas currently targeted for replacement are summarised as follows. While the primary objective is to eliminate ageing lines, prioritisation for age replacement considers, past failures, general asset condition and the need for growth and security provision.

Location	Lenght
Tokomaru – Ruatoria Tie	2km
Frasertown Feeder	4.5km
Raupunga Feeder	5km
Lavenham Rd Feeder	2km
Wainui Beach	1.5km
Tolaga Bay – Anarua Bay	2km
Bushmere Rd Feeder	3km

Uneconomic Rural line replacement commences in 2009/2010 at approximately 20km p.a. costing $ 600,000 p.a.

Poles

Target replacement of 450 poles at $3300 ea. per year is planned until less than 10% of the wood pole population has remaining pole strength lower than the design load. $1,500,000. p.a.

Cables

Replacement is driven by the need for capacity upgrades and new work which is identified on a project-by-project basis. Therefore targeted replacement due to age is 0km.
When multiple failures are experienced on sections of cable replacement is built into project work. Currently there are no projects specifically in this category.

GROWTH

Constraints and Triggers

In ENL's overhead network the constraint is generally driven by voltage drop. A design standard of 2.0% maximum is applied to new lines and permitted to reach to 5% before reinforcement is considered. Other factors such as the need for contingent capacity to meet security needs are also considered. Analysis is recorded the ENL Security Review, Load Forecasting Model and Network Development Plan.

Cable network tends to be more constrained by thermal ratings. Therefore underground systems are less tolerant of constraints.

ENL's past standard of 11kV line construction uses a range of conductors as shown in the following table:

CONDUCTOR TYPES 11KV	
conduct_code	**Length km**
16mm Cu	0.13
19/14 Cu	47.00
19/16 Cu	43.90

CONDUCTOR TYPES 11KV	
conduct_code	Length km
19/17 Cu	9.57
19/18 Cu	2.76
3/12 Cu	0.16
3/12 St	245.60
3/128 Cu	15.33
7/.093 Cu	33.62
7/.118 Al	1.74
7/.118 Cu	37.12
7/12 Cu	0.70
7/14 Cu	566.44
7/14 St	2.62
7/16 Cu	443.07
7/16 St	385.34
Cockroach	0.13
Dog	69.39
Ferret	121.48
Flounder	18.73
Gopher	153.37
Kutu	0.41
Magpie	25.19
Mink	4.38
No 6 St	0.41
No 8 Cu	28.86
No 8 Fe	0.49
No 8 St	26.96
Rabbit	4.43
Racoon	34.11
Rango	55.41
Robin	13.60
Shrike	14.68
Squirrel	3.17
Swallow	3.25
Swan	5.39
Weke	34.71

Ability of the 11kV to accommodate load growth is generally constrained by voltage considerations as opposed to capacity rating.

Forecasts

The Load Growth section of this document identifies when growth will cause load to exceed 11kV capacity. For feeders selected for duty as tie feeders providing contingency capacity to other feeders/substations there is a need to maintain spare capacity. In many cases there is limited or no contingent capacity remaining. These have also been identified.

Summary of Actions

Lines

YEAR	ACTION	ESTIMATE $
2004/2005	Mahia 6km	180,000
2005/2006	Tamarau Feeder Sponge Bay-Wainui 1.7km	51,000
2005/2006	Wairere Rd 1.5km	45,000
2005/2006	Patutahi Line alterations 1.2km	36,000
2005/2006	Bell Rd 1km	30,000
2006/2007	Matawhero-Muriwai feeder 4km	135,000
2007/2008	Dalton Feeder Moana Rd Bypass 1.4km	98,000
2008/2009	Ngatapa to Otoko Hill 8km	250,000
2009-2011	Reinforce Cricklewood Spur 13km	390,000

An allowance of 2.0km p.a. at $70,000/km and 10 pole failures at $4000ea is made for unplanned network extension and fault replacement. Total allowance $180,000 p.a.

Cables

11kV Cables that need to be upgraded for growth and security within the next 10 Years are indicated below.

Year	Location	Existing Size	New Size	Length	Cost
2004/05	Masonic Sub Lowe St To Farmers Sub Customhouse	16mm Cu	95mm Al	160	$30,400.00
2004/05	Masonic Sub Lowe St To Govt Building Lowe St	16mm Cu	95mm Al	180	$34,200.00
2004/05	Nelson Rd –Campion Rd 11kV Tie		300mm Al	185	$35,000.00
					$99,600.00
2005/06	Masonic Sub Lowe St To Bright St Sub	16mm Cu	95mm Al	150	$28,500.00
2005/06	Farmers Sub Customhouse To Reads Quay	16mm Cu	95mm Al	260	$49,400.00
2005/06	Reads Quay to Weigh Bridge (Gladstone Rd Bridge)	70mm Cu	300mm Al	300	$63,000.00
					$140,900.00
2006/07	Childers Disraeli Cnr	95mm Al	185mm Al	50	$60,500.00
2006/07	Roebuch Rd Palmerston Cnr	70mm Cu	300mm Al	50	$60,500.00
2006/07	Roebuck Rd Bridge	70mm Cu	185mm Al	350	$70,000.00
					$191,000.00
2007/08	Carnarvon Sub to Childers Rd x 2	70mm Cu	185mm Al	280x2	$112,000.00
2007/08	Stanly Rd Bridge	95mm Al	185mm Al	400	$80,000.00
2007/08	Plunket Sub to Ormond Rd (Peel St Bridge)	70mm Cu	300mm Al	320	$67,200.00

					$259,200.00
2008/09	City Feeder (Carnarvon-Pac'N'Sav)	70mm Cu	185mm Al	525	$105,000.00
2008/09	Kahutia St Feeder (Carnarvon-Barry)	70mm Cu	185mm Al	1100	$220,000.00
					$325,000.00
2009/10	Reads Quay to Inland Revenue Sub	70mm Cu	300mm Al	290	$60,900.00
2009/10	Inland Revenue Sub to Plunket Sub	95mm Al	300mm Al	330	$69,300.00
					$130,200.00
2010/11	Weigh Bridge to Hirini St	95mm Al	300mm Al	370	$77,700.00
2010/11	Oak to Stout	70mm Cu	300mm Al	375	$78,750.00
					$156,450.00
2004/05	Port to Reads Quay in City ring project		300mm Al		-
2006/07	Port New Rd (External Funding)		300mm Al		-

An allowance of 1.0km p.a. @ $200,000/km is made for routine network extension.

Gladstone Rd Project

The existing high profile line on the main arterial route for Gisborne has aged to a point where replacement is due. Significant redevelopment of the road has changed the loading and required security characteristics. The projected encompasses Switchgear, 11kV/LV cable alterations and line work.

YEAR	ACTION	ESTIMATE $
2005/2006	Charmers Rd to Lytton Rd	470,000
2006/2007	Lytton to Stanley Rd	500,000
2007/2008	Stanley Rd to Roebuck Rd	650,000

RELIABILITY AND SERVICE

Standard

The standard to be targeted is nil failures in economic network segments due to pole, conductor and hardware failure that can be prevented through active management. Where faults on uneconomic lines can be isolated from affecting economic portions via say a recloser and where there is low risk to people, pole failures are expected and used to drive maintenance programs.

Justification

The 11kV network dominates ENL's asset base and drives the underlying level of cost and reliability performance. Pole condition dominates maintenance programs and the resource applied to managing the network.

Criticality

At this Voltage level the criticality is divided into three ratings.
Urban 11kV is given a class I rating no failure
Rural 11kV is given a class II rating failure with short return time < 60 min
Uneconomic rural lines is given a class III rating failure with longer return time <6hrs.

This asset is critical to reliability and therefore replacement programs should be structured with their criticality in mind.

Gap Analysis

Component	Failures P.A
Poles	8%
Conductor	20%
Binder	10%
Insulators	10%
Crossarms	6%
Trees	17%
Animals	6%
Vehicles	9%
Other	5%
Cable	2%
Lightning	3%
Terminations	4%

Defects are prioritised for remedy in accordance with their criticality and expected remaining life. If components are still failing in service, or the backlog of defects is increasing, then the planned replacement rate needs to be increased. Some sections of the network are constructed with double circuit overhead lines that are no longer necessary, but exhibit frequent faulting due to conductor clashing and wrapping.

Analysis indicates that ENL is experiencing a reduction in pole failures due to extensive replacement work in 2001. However conductor and crossarm failures are increasing. This is addressed in the replacement program.

Summary of Actions

Replace double circuit with larger conductor from Tokomaru to Ruatoria. As per replacement program.

PERFORMANCE ISSUES

Component Failures

There is 661km of galvanised steel conductor on the network. Approximately 130km is rusting badly to the point where regular breakages are occurring. This conductor requires replacement over the next 10 years.

The replacement program assumes 20km/year for all conductor. Around 50% of this will be allocated to Galvanised steel conductor replacement.

From 2013 conductor replacement will increase from 20km p.a. to 40km at $1,2000,000 p.a. to align with steady state replacement targets and allow for the peak of the age profile installation pattern.

The trigger point for reconductoring investigation is more than 2 breaks in 3 years on a 5km or less section of line.

Kidney insulators and strings of discs are known to be susceptible to noise creation. These are to be replaced with polymer strains as opportunity presents itself.

Schedule of Actions

As per replacement program

COMPLIANCE ISSUES

Monitoring

The main compliance issue associated with 11kV lines is pole strength. The condition assessment process identifies and forms the basis for managing poles by calculating remaining strength of the pole and comparing this value with the necessary design loading. The resulting safety factor can then be used to prioritise actions which include an assessment made on the benefit of arresting rot or replacement. Using the modelling tools, the optimum method of reinforcing poles can be determined, and the same tools can be applied to new structures to prove engineering standards are complied with.

Standard

Standards and associated actions are documented in the maintenance plan. Poles identified as requiring an inspection will be inspected within 6 months.

Poles proven by inspection to have a remaining strength lower than the required design load will be analysed to determine reinforcement or repair action within 3 months.
Poles with inadequate Safety Factors will be reduced to less than 10% of the remaining wood pole population by the end of each inspection cycle.

Gap Analysis

There is a significant population of low strength poles requiring close management to maintain compliance.

Required Outcome

450 poles are planned for replacement each year. These are prioritised on:

- Safety factor
- Age
- Location risk

A number of these poles will be coordinated with planed conductor replacement progects.

QUALITY AND DEVELOPMENT

Standardisation

Construction of new or replacement asset will adhere to following standards: -

- Concrete poles (hard wood poles where load/strength characteristics cannot be matched)
- Crossarms mounted 200mm below top of pole
- Longer crossarms (2.4m) for live line friendly spacing
- Polymer strain insulators – no strings or kidney
- Line routes to adhere to road reserve where possible
- Standard conductors - Dog – Urban and Rural ties
- Insulators to minimum 15kV standard and for coastal areas 25kV
- Insulators fitted 100mm in from crossarm ends
- All poles to be fitted with possum guard, and pole cap if wooden
- Hardwood strain pole required every 2km in straight prop pole sections of line (to break cascade failures)

- Angle poles to be armless for live line capability.
- Mid span jumpers not permitted
- No stub poles to be used for stay anchors

Cable Standards

- No pitch terminations to be reinstated if any work undertaken
- Terminations on poles to be protected with surge diverters
- Standard cable sizes: 300mm 185mm 95mm AL ,16mm CU
- No cable to cable T connections

New Technology

All technology improvements relate to components standardised on.

Amenity Improvements

Visual amenity will be improved by cleaning structures down of equipment, e.g. ground mounting transformers and road crossings, non reinstatement of attachments, e.g. street lighting, and replacement of under built LT circuits with underground asset. New assets must be placed underground in accordance with district planning requirements.

Generally overhead 11kV asset has quicker repair time and more operational flexibility. These benefits are off set by vulnerability and safety issues in urban areas. Assessment of the appropriate replacement options are carried out on a case by case basis.

NON-ASSET SOLUTIONS

Rural Line renewal

A strategy for rural line renewal was developed in 2003. A combination of reduction in asset quantity, reduction in remaining life and renewal cost sharing is planned for the distribution system in the uneconomic rural section of the line. Details of the strategy are covered in the network development section of this plan.
Alternative solutions will be investigated and advised on a case-by-case basis. The viability of ENL providing alternative are being investigated. Currently no viable solutions have been identified. Hence some rural line replacement will have been completed using traditional methods before acceptable alternative technologies become available.

8.A.3 LT Lines and Cables

DESCRIPTION

Configuration

Description	Total length km
Distribution Lines OH LV Only	111.00
Distribution Lines OH LV Only Remote	19.66
Distribution Lines OH LV Only Roadside	126.09
Distribution Lines OH LV Only Roadside Remote	9.47
Distribution Lines OH LV Only Rugged	7.73
Distribution Lines OH LV Only Rugged Remote	2.81
Distribution Lines OH LV Under built	92.97
Distribution Lines OH LV Under built Remote	18.31
Distribution Lines OH LV Under built Roadside	119.32
Distribution Lines OH LV Under built Roadside Remote	22.27
Distribution Lines OH LV Under built Rugged	4.99
Distribution Lines OH LV Under built Rugged Remote	3.33

Description	Total length km
LV Cables UG LV Only PILC	9.2
LV Cables UG LV Only PILC	0.04
LV Cables UG LV Only PILC Roadside	1.4
LV Cables UG LV Only PVC/XLPE	139.2
LV Cables UG LV Only PVC/XLPE Roadside	31.1
LV Cables UG LV Conjoint PILC Roadside	0.08
LV Cables UG LV Conjoint PVC/XLPE	4.4
LV Cables UG LV Conjoint PVC/XLPE Roadside	1.9

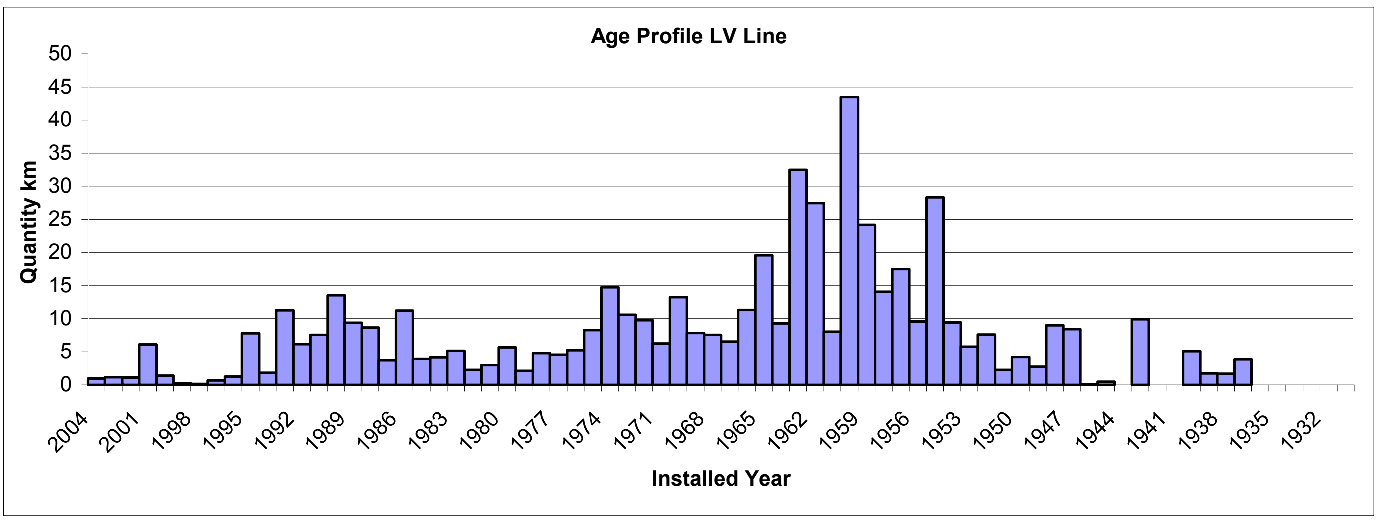
Location

Zone Substation area	No.of Poles	Average Span (m)	Line Length km	Cable Length km
01 Te Araroa Sub	168	49	17.3	1
02 Ruatoria Sub	330	46	34.9	3
03 Tokomaru Bay Sub	319	41	25.9	1
04 Tolaga Bay Sub	269	43	25.1	2
05 Kaiti Sub	1138	32	39.9	49
06 Carnarvon Sub	975	26	22.5	42
07 Parkinson Sub	429	27	13.1	17
08 Makaraka Sub	998	37	48.6	28
09 Patutahi Sub	687	47	81.4	4

10 Pehiri Sub	142	54	15.3	0
11 Ngatapa Sub	138	52	14.2	0
12 Puha Sub	518	45	49.2	3
14 Matawhero Sub	79	45	9.1	5
15 Port Sub	25	27	0.027	2
20 Tuai Sub	328	81	8.1	0
32 Kiwi Sub	2276	59	93.2	32
33 Blacks Pad	346	52	21.3	1
34 Tahaenui Sub	290	55	18.3	0

LIFE ASSESSMENT (Lines)

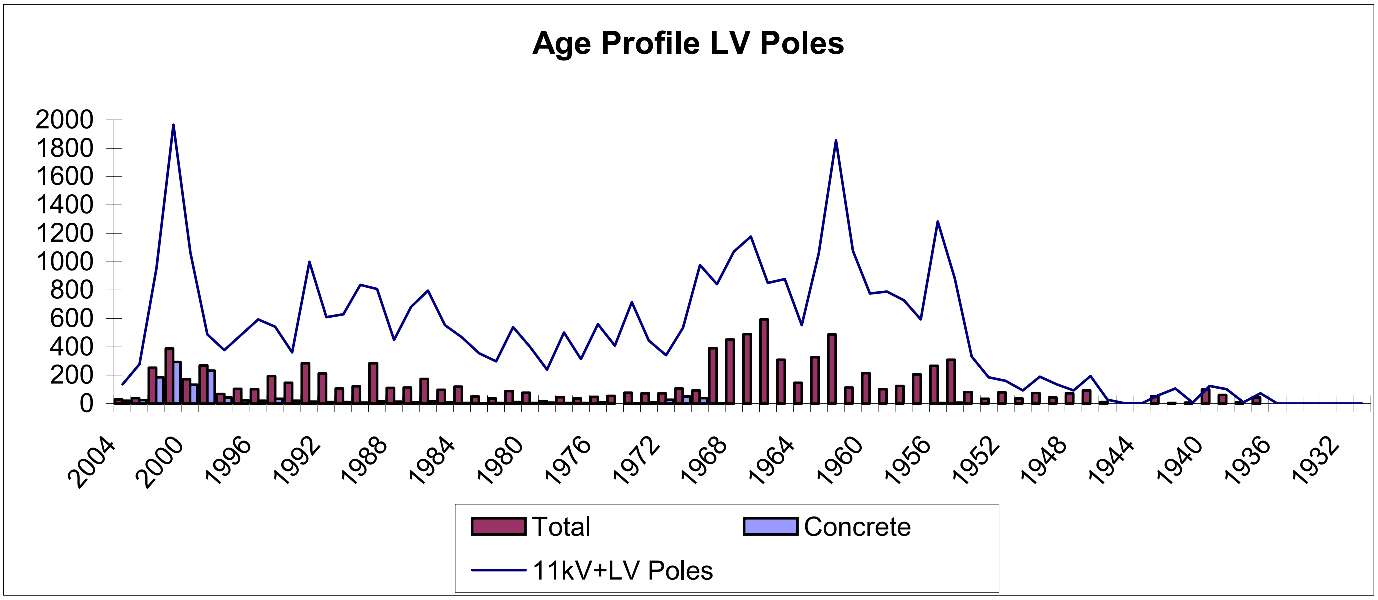
ODV Standard Life	45years
Population Size	538 km
Start of Failure period	45 years
Failure period	20 years
Average Residual Quantity	0
Average Installation Quantity	11km/yr
Targeted Replacement rate	2km
Rate of Growth Additions	0km
Targeted Reduction rate	2km



LIFE ASSESSMENT (Poles)

ODV Standard Life	45years
Population Size	9455
Start of Failure period	35years
Failure period	20years
Average Residual Quantity	0
Average Installation Quantity	210
Targeted Replacement rate	50
Targeted Reduction rate	50

Rate of growth additions	0

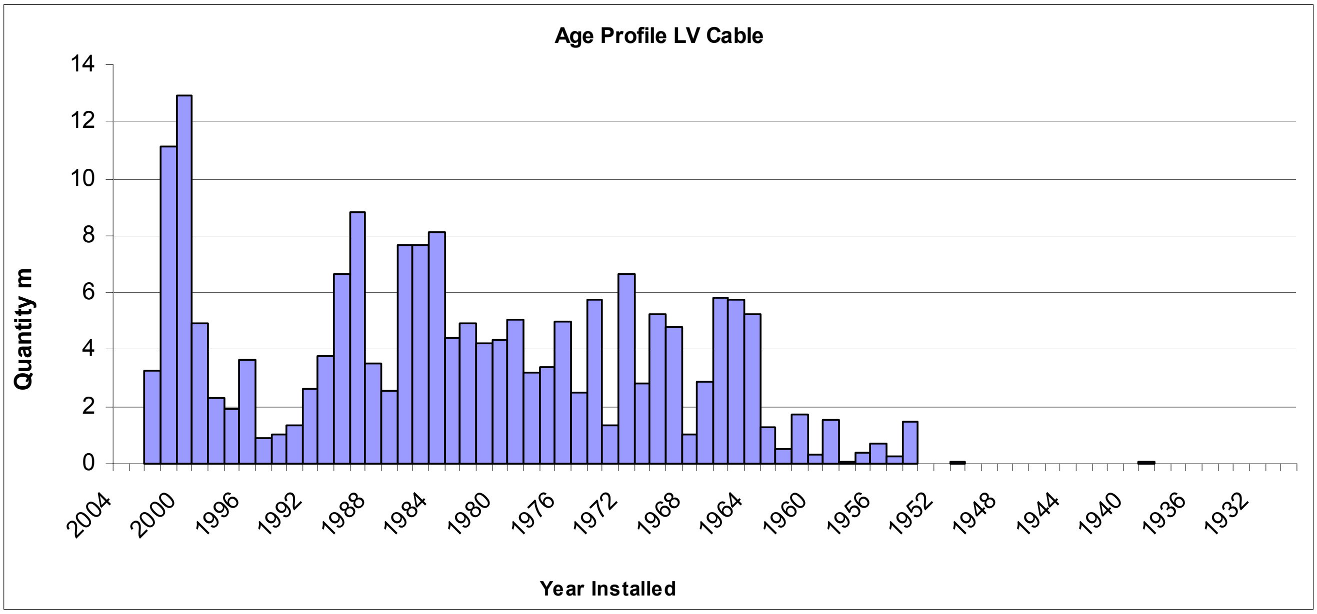


Age Profile Comments

Conductor tends to be replaced far sooner than poles due to capacity upgrades.
Poles tend to be left until in-service failure or need for replacement associated with new connections or conductor upgrade.
Low pole installation has some correlation with under grounding and use of 11kV under building.
Original population of poles very old but still 4 years of 1st replacement cycle remaining.
Average span in urban area very short at 30m.

LIFE ASSESSMENT (Cables)

ODV Standard Life	45 years
Population Size	188 km
Start of Failure period	40 years
Failure period	10 years
Average Residual Quantity	1 km
Average Installation Quantity	4 km/yr
Targeted Replacement rate	2 km/yr
Rate of Growth Additions	4 km/yr



Age Profile Comments

Cable installation rate shows strong correlation with reduction in overhead line installation. Some age replacement evident but driven more by capacity upgrade.
Age profile spread enough to shift to steady state replacement of 4km/yr with 2km p.a. to be renewed with cable.

Replacement Criteria

Spot pole replacement will occur as a maintenance action indefinitely until there is a need to reconductor for capacity. At this time all poles will have to meet increased strength requirements to carry the heavier conductor. Where necessary underground conversion will be applied.

PLANNED REPLACEMENT PROGRAMME

Lines

Replace 2km/year	$80,000 p.a.

Assume 2km per year will be replaced with cable.

Poles

Replace 50 poles per year at	$80,000 p.a.

It is assumed that 75 poles p.a. will be removed due to underground replacement.

Cables

2km/yr steady state for age replacement	$160,000p.a.
2km/yr steady state for growth.	$160,000p.a
2km/yr as a substitute for line replacement.	$160,000p.a

GROWTH

Constraints and Triggers

LV conductors are fused to full duty capacity, i.e. no short duration duty cycle peaks are permitted. This prevents accidental overload as no monitoring is undertaken and there is little control over the load connected in customers' installation. No de-rating is made for damage, aging or trenching conditions. This sets the upper limits on conductor capacity at rating.

The low level of protection and management of load is traded off against longevity of service.

Overhead conductor is installed with an excess contingency capacity of 20% while cables have a contingency capacity of 33%. This contingency erodes with load growth until load equals rated capacity.

The trigger for upgrade is therefore a fuse blowing. Voltage complaints and transformer MDI readings can give an early warning. With load growth ranging between 0.5 and 11% it can be expected that conductor will require capacity upgrade long before age replacement. This justifies the minimal efforts made to lengthen life.

Forecasts

Detailed analysis has not been undertaken on the urban overhead network to identify exact capacity constraints. The cable network, which supplies commercial areas, is monitored more closely.

At present ENL is addressing capacity via additional transformer installation.

In the interim growth on these cables erodes contingency capacity.

The LV overhead network generally is below design standards in terms of conductor size and length of circuit. This is visibly evident and likely to be the main contributor to a relatively high loss factor of on the network. However, some of this gap is contributed to by equally poorly sized service lines. However with transmission capacity becoming an issue for ENL it is appropriate to manage loss more actively through a higher level of design for LV work.

This low standard of LV construction has arisen due to a policy of not upgrading capacity unless age replacement is required. The historical reluctance to avoid capital renewal unless coordinated with under-grounding activity has also contributed. However it is a valid business strategy to trade off capital expenditure for increased losses but this becomes sub optimal in the long term. In urban networks where annual load growth in domestic installations is approximately 1% the 20% security capacity contingency for overhead lines will be consumed in 20 years and the cable contingency of 33% in 33 years.

ENL's domestic load growth has been higher in recent years. Generally transformers overload before cables and this is allowing issues to be overcome through increasing transformer density thus reducing LV run lengths. This approach will be adequate until transformer capacity is not needed for the load density it is more economic to reconductor.

Summary of Actions

Refer replacement programme

RELIABILITY AND SERVICE

Standard

There is no reliability or service standard other than the inherent cost penalty of fault repair for ENL.

Justification

Faults on LV network affect limited numbers of customers and often only one. No disclosure of LV performance is required. To own and operate LV assets does not require specialist skills to the same degree as HV asset; therefore performance is exposed to the competitive pressures of by-pass.
Criticality

LV overhead circuit is considered low criticality as repair is easy and limited consumers are affected.

Cables in the CBD are considered medium criticality as access and path reinstatement is difficult. Outages affect business and security.

Gap Analysis

No analysis has been undertaken in absence of data. However faults tend to indicate issues of poor condition and quality of installation.

Poor condition is age related and the result of minimal maintenance activity. This situation is the result of low growth periods during the asset life preventing regular upgrade. It affects mostly overhead assets and examples include conductor wrapping, and connector failures.

Quality of installation is vital to cable reliability particularly aluminium cables. There is no remedy other than control of standards.

Summary of Actions

Nil.

COMPLIANCE ISSUES

Monitoring

Pole strength is designed and monitored in the same fashion as other poles.

Standards

Standards and associated actions are the same as 11kV distribution.

Gap Analysis

The use of suicide poles is not permitted in order to eliminate a known hazard. Every opportunity is actively sought to eliminate their presence. Their smaller cross-section and frequent use as tap-offs means they are being condemned at a faster rate than normal poles.

Road crossing poles have similar strength issues as suicide poles, without the benefit of being supported in line. The use of Telecom poles often means these poles never had strength necessary to comply with power company standards. Little or no monitoring and management of compliance is undertaken by Telecom with regard to electricity assets. All new crossings or reinstatement of existing crossings will be thrust and cabled under the road as standard practice. This will prepare the way for eventual under grounding of the main line as laterals need to be under grounded first.

Required Outcome

Pole replacements and repair program identified in maintenance section.

Suicide poles eliminated by 2014
Road crossings under grounded by 2014

QUALITY AND DEVELOPMENT

Standardisation

Construction of new or replacement asset will adhere to the following standards: -

No reinstatement of pilot
No reinstatement of O/H street lighting
Wasp PVC covered conductor for overhead
Beetle (106mm2) domestic cabled LV reticulation
Huhu (185mm2) commercial cabled LV reticulation
25mm2 NS Cu. For road crossings
No under-building on 50kV poles
Cables to be run for first span from distribution sub. No more than 1 termination per pole.
Elimination of road crossings, overhead crossovers, mid span jumpers and substation by-pass via overhead circuit.

New Technology

New technology is applicable at a component level. ENL monitors product development via normal suppliers and through involvement in industry forums and conferences.

Amenity Improvements

The number of conductors, their covering, number of lateral connections, etc. makes LV distribution ugly in comparison to clean HV structures. The span is dictated by property boundaries for service take offs and this increases pole numbers. Cleaning HV pole lines down from LV under building greatly improves amenity. More value is achievable from under grounding programs if they target lower cost LV network before HV is considered.

Programs need to be preceded by:

Under grounding of service lines
Under grounding of road crossings
Transfer from pilot to ripple
Replacement of street lighting circuits and support structures

Priority can be assigned on:

% of above complete
Trench reinstatement costs
Contributions from customers or local authorities
Need for capacity upgrade or replacement

No program exists in the medium term for under grounding as adequate progress is being achieved, driven by other issues.

PERFORMANCE ISSUES

Component Failures

The main performance issues are related to age and a minimal maintenance practice. They are:

Failing connectors causing conductor burning
Breaking conductor
Stretched and sagging conductor vulnerable to wire wraps and being caught by high vehicle loads

These are attended to as they occur and not proactively managed.

Overhead lines are managed in a reactive mode when fuses overload and voltage complaints are received. Approximately 30 complaints are received per annum and 2 LV distribution fuses blow per annum due to genuine overload. LV conductor is fused to full duty rating. Often during faults this rating is exceeded for short periods, particularly on overhead open lines. Where this has occurred regularly there is evidence of conductor life being shortened due to annealing of HD Cu., i.e. loss of tensile strength resulting in breakages.

NON-ASSET SOLUTIONS

Low Voltage asset is relatively easy to be owned and operated by other parties such as consumers and developers. There is scope for shifting connection point and asset ownership in favour of those who wish to manage their supply to different standards than ENL's "one solution fits all" approach.

8.A.4 Service Connections

DESCRIPTION

Responsibility for service lines has been formally handed over to consumers. Regardless of ownership consumers are required to fund and manage their connection so that it meets the requirements of regulations and ENL's Connection Standard. Failure to do so is controlled by ENL's right to disconnect in order to protect other customers and its equipment.

This section therefore deals with the service laterals from the main distribution feeder to the point of connection (usually the service fuse) and the management of Service fuses and Distribution Pillars.

Description	Approximate Quantity
Service Connections LV Overhead - 1ph	4925.00
Service Connections LV Overhead - 3ph	13708.00
Service Connections LV Underground - 1ph	5231.00
Service Connections LV Underground - 3ph	1012.00

Distribution Pillars		
Description	**Type**	**Quantity**
Discon Box	Unknown	1130
Discon Box	Inground Pit	432
Discon Box	Lge Black Plastic	55
Discon Box	Med Green Shear	320
Discon Box	Sml Black Plastic	300
Discon Box	Sml Fibreglass	300
	Total	2537

Data is relatively incomplete. ENL is undertaking data capture exercises to identify the asset in greater detail to improve lifecycle and safety management of these assets.

LIFE ASSESSMENT

Not currently measured as ENL does not manage renewal.

PLANNED REPLACEMENT PROGRAMME

As required by other work on network assets. No capital expenditure planned other than compliance issues.
Allowance for steady state replacement from 2011/2012 $20,000 p.a.

GROWTH

The net quantity of connections is declining as customers continue to aggregate multiple connections to a common connection point.
Full cost recovery is made from the customer for new connections.

RELIABILITY

Failure of service fuses and connectors are the main faults. No preventive replacement programs are undertaken due to difficulty in predicting aging as this is dependent on loading conditions.

Approximately 25% of fuse bases require replacement when the fuse needs replacing. This is caused by burning on the terminal of lose jumper connections or corrosion. The problem is related to quality of the product and installation.

Service failures are treated as non-critical because they affect only one connection.

COMPLIANCE ISSUES

Voltage drop in the customers' service main is the major regulation non-compliance. ENL has not actively managed this in the past as it generally only affects the service of the consumer responsible for it. However high losses do reflect into the costs of the network and are shared by all customers. ENL will therefore issue notices under its terms and conditions for connection to require undersized connections to be upgraded. Contractors will be requested to follow up notices with an offer of service.

Poor power factor is a similar issue and affects the need to invest in transmission capacity. Offending installations will be handled in a similar fashion, i.e. penalty charge. ENL's system power factor is 0.93 (0.88 without POS capacitor correction). This needs to be improved to 0.96 to maximise transmission capacity.

Harmonic generation will be handled via penalty charging where it only affects ENL equipment. If it affects other consumers then disconnection and compensation to those consumers will be enforced.

Controlling the connection of unadvised load is achieved by fusing to nominated capacity where this proves to be an issue. Illegal connection continues to be a revenue protection issue.

All connections are required to have a valid COC prior to livening.

In some areas of the network service fuses are housed in metal clad meter boxes on the property boundary. As meter boxes they are owned by Contact Energy. Many of these boxes are damaged and in an unsafe state.

ENL has removed its equipment from the meter boxes and relocated into new service fuse boxes completion of this current issue is in 2005/2006 costs have totalled $30,000 p.a.

There is a similar issue with sun damaged fibreglass service fuse boxes. There are 300 boxes of this type to be replaced, i.e. 50/year @ $850 each - $40,000p.a. until 2010/2011.

QUALITY AND DEVELOPMENT

Domestic installations have traditionally been supplied via 4 wire (2 phases, pilot, and neutral) service lines. This was a means of keeping conductor size small by meeting capacity requirement via more conductors. Single phase connections without pilot are to be standardised on. This reduces the quantity of connection hardware by 66% and reduces the probability of equipment failure. This will be encouraged at the time of upgrades via a differential in fixed charges for multi phase versus single phase connections.

All new connections and upgrades will encourage under grounding by providing the point of connection in a boundary located service fuse box, i.e. installation of pole fuses will be discontinued. This cleans down the structures of hardware, aids accessibility, and prepares the way for under grounding the main line.

Pole fuses will still be permitted in rural areas however preferred connection will be via cable only to eliminate pole loading issues.
For customers not wishing to underground a UDOS pole located on their property is an alternative.

No T joints will be permitted for service lateral take-offs on underground distribution cables.

During renewal programs no pilot wire will be reinstated. The installation will be converted to ripple control.

PERFORMANCE ISSUES

None in addition to the above.

NON-ASSET SOLUTIONS

Issue service line volt drop and safety non-compliance notices to customers.
Customers are able to negotiate directly with independent contractors for corrective measures.

8.A.5 Load Control

DESCRIPTION

Currently 3 Load Control Transmitter facilities exist for control of Ripple Relays In the Gisborne and Wairoa Regions.

- Valley Road –11kV Installation 315 HZ (not in service)
- Makaraka – 50kV Installation 315HZ
- Wairoa – 11kV Installation 1250HZ

A cascade pilot wire network consisting of 10 pilot feeders traditionally operated a majority of the Gisborne City Area load control. This system was broken onto small sections controlled by Ripple relays at strategic points in 2002. The small quantities of the resulting pilot system typically consist of 10 to 20 contactors.

Ripple Relays Gisborne 8875 installed between 1990 and 2004
Contactors and Pilot wire controlled installations Gisborne 4755
Trustpower owned installations Wairoa 2000 approx.

The Controllable capability of the system is shown in the following table.

		CHANNEL	CAPACITY	
1	1	Te Araroa	0.3	MW
2	2	Ruatoria	0.6	MW
3	3	Tokomaru Bay	0.4	MW
4	4	Tolaga Bay	0.5	MW
5	5	Wainui/Whangara	0.7	MW
6		Tamarau	1.0	MW
7		Kaiti #1	0.9	MW
8		Kaiti #2	0.6	MW
9	6	Town	0.5	MW
10		West End #1	1.1	MW
11		West End #2	0.7	MW
12	7	Te Hapara #1	0.6	MW
13		Te Hapara #2	0.5	MW
14		Matawhero/Makaraka	0.4	MW
15		Whataupoko #1	0.5	MW
16		Whataupoko #2	0.6	MW
17		Mangapapa #1	0.9	MW
18		Mangapapa #2	0.7	MW
19		Westpark/Matokitoki	0.3	MW
20	9	Patutahi/Waipaoa	0.4	MW
21		Waimata	0.6	MW
22		Muriwai/Te Arai	0.6	MW

23	10	Pehiri	0.2	MW
24	11	Ngatapa	0.2	MW
25		Matawai	0.3	MW
26	12	Puha	0.5	MW
		Wairoa 00	381	kW
		Wairoa 01	116	kW
		Wairoa 02	327	kW
		Wairoa 03	552	kW
		Wairoa 04	508	kW
		Wairoa 05 Night store	25	kW
		Wairoa 06	511	kW
		Wairoa 07	545	kW
		Wairoa 08	519	kW
		Wairoa 09	537	kW
		Wairoa 16 Night store	48	kW
		Wairoa 17	168	kW
		Wairoa 18	179	kW
		Wairoa 19	497	kW
		Wairoa 30 Flood Pump	118	kW
		Wairoa 31 Spa Pool	30	kW
		Wairoa 32 Cold Store	60	kW

LIFE ASSESSMENT

ODV Standard Life	Installed	Replace
Valley Rd	1987	N/A
Makaraka	1984	2019
Wairoa - Transmitter	1989	2024
- Cell	1965	NA

PLANNED REPLACEMENT PROGRAMME

Total number of relays to Eliminate the Contactor / Pilot System.
Gisborne 4755
Wairoa 2000

Replace / Install 1200 relays per year at a total cost of $250,000 p.a. until 2010/2011

RELIABILITY AND SERVICE

Due to the high maintenance effort required to keep the pilot system operational and its inflexibility in terms of control options, it is being phased out in favour of ripple relays. This will require replacement/reprogramming of all relays in the long term.

Contingency Provision

No contingencies other than manual control and use of generation exist as an alternative.
The Gisborne region is controlled via a single 50kV injection point at Makaraka. There is a high dependency on the operational availability of the plant. Failure of critical components resulting in plant down time has a significant cost impact on the business. There are long lead times for critical components for the plant. In order to provide for failures the purchase of critical spare components is required. In the longer term establishment of a second injection point is planned.

The Wairoa Injection point is not considered as critical in its current state.

Summary of Actions

Acquire spares 2005/2006	$200,000
Install 2nd Injection point 2009/2010	$200,000

COMPLIANCE ISSUES

Nil

QUALITY AND DEVELOPMENT

New Technology
The use of radio communications technologies to operate receivers directly in areas where injection signals are poor is being monitored. Currently the industry does not offer product solutions to achieve this.

PERFORMANCE ISSUES

The Wairoa system operates at 1250 Hz, which is subject to high signal attenuation potentially resulting in ineffective control. It is planned to install the ex Gisborne Massey Rd 11kV coupling cell at Kiwi substation in 2004/05. The ex Gisborne coupling cell operates at 317HZ and signal attenuation issues at this frequency have proven to be less common. The existing and newly installed plants will both be operated for a period of 2 years to enable the existing relays to be changed to operate on the new frequency.

8.A.6 Major Substations

DESCRIPTION

Includes general items only - earthing, fencing, access, control, buildings and land. Details of other components are included in the sections for Zone substation Transformers, Protection and Control equipment, Circuit breakers, Pole mounted isolation equipment and 11kV Switchgear.

Zone substations, points of supply and significant sites for Eastland Network are:

- Transpower Gisborne Point of Supply Massey Rd(50kV)) includes Valley Rd Load.
- Transpower Tokomaru Substation (50kV)
- Transpower Tuai Point of Supply (11kV)
- Transpower Wairoa Point of Supply (11kV) includes Wairoa 11/33kV substation
- Blacks Pad Zone Substation
- Tahaenui Zone Substation
- Te Araroa Zone Substation
- Ruatoria Zone Substation
- Tokomaru Zone Substation
- Tolaga Bay Zone Substation
- Kaiti Zone Substation
- Port Substation
- Carnarvon Street Zone Substation
- Makaraka Zone Substation
- Parkinson Street Zone Substation
- Matawhero Zone Substation
- Patutahi Zone Substation
- Puha Zone Substation
- Ngatapa Zone Substation
- Pehiri Zone Substation
- Kiwi Substation (Waihi injection point)
- Waihi Power Station
- Hexton Switching Station
- Goodwin Rd Switching Station
- Matawai Voltage Regulator *
- Tatapuri Voltage Regulator *
- Kopuroa Voltage Regulator *
- Kanakania Voltage Regulator *
- Waingakane Voltage Regulator *
- Mahia Voltage Regulator *
- Nuhaka Voltage Regulator *
- Waihua Voltage Regulator *
- A Park 11kV Sub Station Wairoa *

- Bright Street 11kV Substation *
- Plunket Rooms 11kV Substation *
- Reads Quay 11kV Substation *

The following per substation descriptions contain:

- A brief history
- Description of main Asset components contained in each substation.
- Identified issues pertaining to each substation.
- Identified actions planned at each substation.

* Voltage regulator sites and smaller distribution subs excluded

Transpower Gisborne (Massey Rd) Substation

Gisborne substation was built in 1953 supplied from a double circuit 110kV tower/pole line from Tuai and has been upgraded to the present capacity. The last section of line, from Patutahi to Massey Rd, separates to 2 single Circuit Pole lines.

The substation comprises

- Two incoming 110kV circuits from Tuai
- One outgoing 110kV circuit to Tokomaru Bay (Not used by ENL)
- 1 110kV capacitor Bank
- 1 Transformer bank 110/11kV 10MVA T1 (Not Connected to ENL)
- 1 Transformer bank 110/11kV 20MVA T2 (Not Connected to ENL)
- 2 Transformer banks 110/50kV both 30MVA T3, T4
- 2 50kV Incomers
- 4 50kV Feeders to ENL, 2 on each half of the 50kV bus.

Issues

The capacitor bank on the 110kV system causes signal loss on ENL injection system.
The 110kV line to Tokomaru Bay is not used by ENL however it remains in service to provide 110kV voltage support via the line capacitance.
Earthing resistors are required to limit earth fault levels - inductive interference to telecommunications circuits.
There are no Tap changers on 110/50kV transformers.
ENL have no control/indication functions on the 50kv feeder circuit breakers.
Transpower easements for a 110kV a proposed line route from Wairoa to Gisborne 2002 were not secured. This is no longer considered a viable option and Transpower System Security Forecast indicates load management and generation alternatives as an interim solution.
Operation on a single 110/50kV transformer bank constrains ENL to between 35 and 40MVA
ENL is not contracted for n-1 supply security at this site. The 50kV Bus is run tied via ABS 's and a single 50kV bus fault event will interrupt supply to the entire Gisborne region.

Similarly at Tuai the 110kV lines supplying ENL are on a 110kV ring bus tired via a Circuit breaker that is not equipped with bus protection hence any fault on the 110kV bus at Tuai will also interrupt the entire supply.

Valley Rd Injection Plant

This site is adjacent to the Massey Rd Substation. It currently houses the redundant 11kV ripple injection plant.
The site is considered strategic in terms of its ability to be used as an 11kV switch room if a 50kV/11kV zone substation were to be required at the site.

Actions
It is intended that the 11kV ripple injection plant be relocated to Wairoa.

Transpower Tokomaru Bay Substation

The Tokomaru Bay substation was built when the single circuit 110kV tower/pole line was constructed from Gisborne in 1978/80.
The substation comprises

- 1 Transformer bank 110/50kV 10MVA (Currently disconnected)
- 1 outgoing 50kV circuit to Tokomaru Bay (Not used by ENL)

The 110kV line is currently energised at 110kV however from the open incoming 110kV isolator switch the 110kV bus is directly connected through to the 50kV bus and the transformer bank is disconnected. ENL's 50kV Network is isolated from the Transpower sub by an open 50kV ABS.

Issues

The transformers have no OLTC and have been sitting de-energised since bypass in 2001 it is unlikely that Transpower would ever re-liven these units without an overhaul.

ENL has no intentions to purchase this line from Transpower as it's own 50kV line has proved adequate since bypass. Diesel generation provides the necessary security to the East Coast area in lieu of the Transpower line..

Transpower Tuai Substation

The Transpower supply point at Tuai is supplied from 1 x 10MVA 110/11kV transformer bank through 11kV switchgear with two outdoor reclosers (KFE's). The KFE reclosers were installed in 2000 and fitted with Transpower's SCADA control.

Issues

The SCADA controls are unreliable and restoration times are high as the Transpower maintenance contractor is based in Napier and the Napier based contractor has no formal sub-contract with contractors based in Wairoa Auto-reclose to lockout events require a site visit to set the reclosers to 1 shots prior to recluse following a fault.

The Wairoa 11kV network is not connected to the Tuai 11kV network. The cost of the connection assets is high given the total load of the area is around 600kVA. An alternative supply to Tuai via the Wairoa 11kV lines is a consideration discussed in the Network Development section. A second consideration is to obtain an 11kV supply from the Genesis 11kV generator bus.

Actions

Develop a long-term solution to Bypass Transpower connection assets for 11kV supply at Tuai.

Transpower Wairoa Substation

Wairoa substation was built in 1939 and in 1997 the 11kV indoor switchgear was upgraded to new Reyrolle vacuum circuit breakers. In 2000 Transpower upgraded the double circuit Tuai tower/pole line to 110kV and replaced the two transformer banks. Only 2 of the 11kV feeder CB's are used to provide supply to ENL since rationalisation in March 2002.

The substation comprises

- 2 Transformer banks 110/11kV 10MVA
- 2 110kV incoming lines
- 1 11kV switchboard, 2 Incomers, Bus tie and 6 feeders . (Only 2 feeders connected)

Issues

There is a possibility of connection of generation (20 to 40 MW) at a site near Frasertown. Transpower's charges for establishment of an independent connection are prohibitive. Transmission costs could be avoided by connection to ENL's network or vice versa.

The 11kV switchboard arrangement is excessive in terms of ENL's requirements. The switchboard could be reduced by a number of panels.

The existing 11kV cables from Transpower to ENL lines limit the Capacity to ENL to 8MW on either circuit. These cables are short runs of 40 meters and planning is underway to upgrade them.

Wairoa 11/33kV Substation

Located on the Transpower site ENL operate a 11/33kV step-up substation to provide supply to the 33kV Mahia line. The Transformer was installed in 2000 with new fencing Bunded pad and oil containment facilities. Alterations were made to the Load control facility at the site in 2001 eliminating all compliance issues.

The substation comprises

- An 11kV Incoming line from Kiwi Substation
- 1 Pole mounted 11kV circuit breaker used for Transformer protection.
- 1 11/33kV (YD1) 2.5MVA 3 Phase Transformer.
- An 11kV Load control injection facility.

Issues

The Load at Mahia has increased to the point where the transformer begins to overheat during Christmas and Easter Peaks.

There are duplicated 11kV circuits between this substation and Kiwi substation that can be rationalised with the Waihi 50kV circuit which passes 60m from the site on route to Kiwi substation.

Actions

The Network Development Plan covers rationalisation of the 50kV Waihi line to 33kV and relocation of the 2.5 MVA transformer to Mahia.

The redundant 11kV Load control Plant from Valley Rd Gisborne 315HZ is programmed for installation at Kiwi Substation and following conversion of the 1250HZ relays owned by Trustpower to 315HZ the existing Load control injection plant at this site will be removed.

Blacks Pad Substation

Blacks Pad Substation was established in 1976. It is located between Nuhaka and Mahia Beach Initially the substation comprised a 5MVA single-phase transformer bank installed by the NZED, supplied via a 50kV line from Wairoa. In 2000 the 50kV line was converted to 33kV and the transformer replaced.

The substation comprises

- Incoming 33kV Dropout fuse protection
- A 1.5 MVA 3Phase transformer with manual tap settings.
- 1 Pole mounted 11kV circuit breaker

Bunding, fencing and earthing upgrade work was all completed in 2000 in conjunction with the transformer change.

Issues
The substation reaches its capacity at Christmas and Easter peaks. This has been alleviated by the installation of 1MW diesel generation at Mahunga for the short term.

Actions

No actions are required at this substation. Refer to the Network development plan for details on the 33kV line extension and additional capacity at Mahunga near Mahia.

Tahaenui Substation

This substation is located between Wairoa and Blacks Pad Substation. It was constructed with all new equipment in 2000. The substation is used primarily to supply load to the Morere Area and provides limited security to Blacks Pad substation.

The substation comprises

- Incoming 33kV Dropout fuse protection
- A 1.5 MVA 3Phase transformer with manual tap settings.
- 1 Pole mounted 11kV circuit breaker
- 1 11kV Ring Main Unit

Issues
Nil

Carnarvon Street Substation

This substation was constructed in 1971 initially comprising 1x 3phase 50/11kV 12.5MVA with OLTC (Hawker Siddeley) fed from a single pole line from Makaraka switching station.

The 11kV circuit breakers are Reyrolle LMT comprising 2 incomers 1 bus-tie and 9 feeders, all oil type with Reyrolle mechanical protection relays.

In 1986 Parkinson Street substation was teed off the Makaraka – Carnarvon Street 50kV line. In 1995 a second transformer bank was installed 1x 3phase 50/11kV 12.75MVA with OLTC (IMP) complete with bunding, an alternative 50kV pole line from Gisborne substation was also installed.

The T1 transformer is protected by a Reyrolle OSSMT minimum oil 50kV circuit breaker while T2 has an AEG SF6 circuit breaker. 50kV surge arrestors where replaced on both transformers in 1996.

An Oil separator unit was installed in 1999 capable of servicing both transformers. In Feb 2000 the substation earth mat was upgraded to bring it up to the current earthing standard (ECP35), also 100mm crushed rock was applied.

The substation comprises

- An incoming 50kV line from Transpower Massey Rd
- An incoming 50kV line from Transpower Massey Rd via Makaraka and Parkinson St Substations
- 2 12.5 MVA 50/11kV Transformers
- 11kV Reyrolle switch-board with 2 Incomers, 1 Bustie, 1 fuse SW and 9 feeders.

- 50kV Bus Circuit breaker to allow 50kV operation as a closed ring.

Issues
Bunding and Earthquake arrangements are required for 1 Transformer unit. This work is coordinated with major maintenance planned for the transformer in 2004/2005

Kaiti Substation

Domestic load in the Kaiti area had grown to a stage that it could no longer be supported on the 11kV system, so in 1987 a complete substation was built. A 3 phase 50/11kV 12.5MVA with OLTC AZTEC transformer was installed protected by a Sprecher and Schuh minimum oil 50kV CB. The switch room was constructed to cater for future installation of a second transformer unit complete with 2x Incomers, 1X bus-tie and 7x feeders. The switchgear is all indoor SF6 Merlin Gerin and GEC Midos electronic protection relays are used.

Earthing upgrades were carried out and Oil containment/Capture facilities were installed in 2002

The substation comprises
- An incoming 50kV line from the Transpower Massey Rd substation.
- An outgoing 50kV line to the Port Substation
- 1 12.5 MVA 50/11kV Transformer
- 11kV Reyrolle switch-board with 2 Incomers, 1 Bustie, 1 fuse SW and 7 feeders

The structure is all concrete poles and steel arms with copper pipe bus bars. The building is of concrete block construction built in 1987.

Issues
As Kaiti substation is the only site adjacent to domestic homes a noise issue exists. The unit has a high impedance, which contributes, to the noise level. Some form of noise reduction fencing may be required in the future.

The 11kV cables to Incomer 1 failed in service and the transformer currently supplies load via Incomer 2. Replacement of the Incomer 1 cables is required if a second transformer is ever installed at the site.

Security levels for the substation are constrained until completion of the 50kV Kaiti-Port-Carnarvon link.

Transformer mounting for earthquake restraint is considered marginal. The mounting arrangement will be upgraded when the transformer requires major routine maintenance.

Actions

Nil

Parkinson Street Substation

With the land being zoned industrial the load in the area started to grow to a stage that it could no longer be supported on the 11kV system, so in 1987 a complete substation was built. A 3 phase 50/11kV 12.5MVA with OLTC TYREE transformer was installed complete with 2x incomers, 1X bus-tie and 7x feeders, 11kV all indoor SF6 Merlin Gerin switch gear and GEC Midos electronic protection relays

The Substation is an identical design to Kaiti. The structure is all concrete poles and steel arms with copper pipe bus bars. A new concrete block building built in 1986.

The substation comprises
- An incoming 50kV line via a tee from the Makaraka-Carnarvon Circuit.
- 1 12.5 MVA 50/11kV Transformer
- 11kV Reyrolle switch-board with 2 Incomers, 1 Bustie, 1 fuse SW and 7 feeders
- An SF6 Ring main unit connected to one of the feeders to provide for the local service supply transformer.

Issues

Growth at Cedenco and new growth expected at Montana have consumed the capacity released by JNL. Parkinson St is now unable to support Carnarvon and its own load.

Growth at this substation is high and the fact that it sits off a 50kV tap-off is less than ideal.

More, and coarser, metal is required in the switchyard to improve the earthing standard

Earthquake restraints for the transformer are required.
Oil containment and an oil separation unit are required.

Actions

Installation of T2 and correction of compliance issues scheduled between 2004 and 2006.

Port Substation

This substation was completed in December 2003.
The Substation is the first stage of security provision for the Kaiti area. The second stage comprises completion of the 50kV sub transmission ring to Carnarvon St substation.
The substation is also required to meet the growing load demand on Kaiti and Carnarvon Street substations.

The substation comprises

- An incoming 50kV from Kaiti Substation.
- 1 12.5 MVA 50/11kV Transformer
- 11kV Reyrolle switch-board with 1 Incomers, 1 fuse SW and 4 feeders

Kiwi Substation

This substation was built as part of the Waihi generation installation in 1983, which comprised 4 X 1250 amp and 5 X 630 amp indoor vacuum circuit breakers of GEC manufacture and GEC Midos relays, supply is via 3 11kV feeders from Wairoa and a 6.3MVA 50/11kV Tyree-Power Construction transformer from the Waihi power station. Earthing at the site was upgraded in 2002.

The substation comprises

- An incoming 50kV line from the Waihi Power Station.
- 1 6.3 MVA 11/50kV Transformer
- 2 Incoming 11kV supplies from the Wairoa Transpower substation
- 1 Bus coupler
- 7 11kV feeders

Issues

Kiwi sub is at risk of minor flooding and does so relatively frequently. This places supply to the bulk of the Wairoa network at risk. A stop bank around the perimeter of the substation is required to manage this risk.

Oil capture and separation facilities are required for the Transformer associated with the Waihi generation supply.

The Short cable lengths from the switchgear to the overhead lines outside the substation perimeter limit capacity of the substation and will need upgrading as the load grows.

Actions

The oil capture and separation facilities are programmed to coincide with major alterations to the Current Waihi supply transformer The existing 11/50kV transformer is expected to be replaced by a 11/33kV unit.

Makaraka Substation

Constructed in 1974 to be the 50kV switching point for the Gisborne- Patutahi line, which tapped off to Carnarvon Street substation. This switching station comprised of 2 Reyrolle OSSMT 50kV minimum oil circuit breakers with mechanical protection relays. One of the Reyrolle circuit breakers was repositioned in 1985 to protect the then new 50kV static

injection plant. In 1990 a new 50kV Sprecher & Schuh minimum oil circuit breaker was installed on the Carnarvon Street tap off with solid state GEC Midos protection relays.
In 2000 a 50kV SF6 Merlin Gerin SB6-72 installed for the Matawhero line tap-off, all protection relays changed to Schweitzer 351.

The 2nd incoming 50kV line from Gisborne, which has been tapped off the Gisborne Puha line, was established in 2001. This new line provides the necessary security for the Load at the substation and the 50kV circuits leaving the site. The outdoor 50kV structure is a split bus arrangement. The new T1 transformer can run off either bus, with a Scada controlled Line Isolators to implement the change over.
This site was upgraded from a switching station to a single transformer Zone Substation in 2001 with the installation of a new IMP 12.75MVA transformer. Bunding, a Sepa unit, an earthing upgrade and crushed rock were installed during the upgrade.
The main 11kV switch room was built in 2001 and the small hut for the injection plant was constructed in 1985. All new sections of the 50kV Bus are constructed using Concrete poles and copper bus work while the older sections still have Hardwood poles of varying condition.

The substation comprises

- 2 incoming 50kV lines from the Transpower Gisborne substation.
- 1 12.5 MVA 50/11kV Transformer
- A Portacom Switch room with 11kV Switch Board comprising 1 Incomer 4 Feeders and a fuse switch
- A 50kV Load control Injection Coupling Cell (Outdoor)
- A hut containing a Load control static converter
- 3 Outgoing 50kV Circuits to Patutahi, Matawhero and Parkinson St/Carnarvon St substations

Issues

While the location of the site is central to the Gisborne load making it very strategic, it would be difficult to expand the site to accommodate an 110kV Supply point.

Actions
Nil

Matawhero Substation

This substation was constructed in 2000 with a single 5/7.5MVA IMP Transformer only. The 11kV switchgear consists of VCB Motorpol PowerVac 12 units. Construction was required to supply JNL. Prior to construction JNL was fed from Parkinson St substation via old 11kV cables. These cables are currently used for limited security.
The 2nd transformer bank was installed in February 2003 along with a second 50kV circuit breaker and 2 additional 11kV feeders. The additional transformer was required to meet the growing industrial load in the Matawhero area.
This gives the substation an ultimate design capacity of 14MVA.
The load is now reaching the secure 7MVA base hence security provisions to reinforce the area with a second 50kV line from Parkinson Street in 2004/5 are underway.

As the substation is near new all Oil containment facilities, Earthing and Outdoor structures comply with current ENL standards.

The substation comprises

- An incoming 50kV line Makaraka Substation.
- 2 5/7.5 MVA 11/50kV Transformers
- A Portacom Switch room with 11kV Switch Board comprising 2 Incomers 1 bus coupler 5 Feeders and a fuse switch
- An outgoing 50kV circuit .
- 50kV Bus Circuit breaker to allow 50kV operation as a closed ring.

Issues

11kV supply to JNL is limited to the Capacity of a single feeder from the substation. In order to provide for Load growth at JNL an additional 50/11kV substation will be required.

The substation is close to a major river. Failure of the stop bank was considered during the substation design and is not expected to hinder operation of the substation.

Actions

Nil

Ngatapa Substation

This substation was built in 1964 when the 50kV ring was built between Puha substation and Patutahi substation. The original single phase transformer units were removed and replaced with 2 very old 3-phase 50/11kV 0.5MVA units. As there are no OLTC's on the transformers a 1500kVA voltage regulator manufactured in 1962 is used to regulate voltage at 11kV.
The structure is all wooden poles and wooden cross arms with copper wire bus bar.
The 11kV circuit breakers were replaced in 2000 with pole mounted SF6 GVR's. Protection relays are solid-state 351P type.
The control building is a small hut.

The substation comprises

- 1 incoming and 1 outgoing 50kV line forming the 50kV ring from Makaraka to Hexton Switching station which also supplies the Patutahi ,Pehiri and Puha Substations.
- 2 0.5 MVA 50/11kV Transformers
- 1 Voltage Regulator
- 1 11kV Incomer and 4 11kV Feeders on an outdoor bus

Issues

This substation is ideally suited to upgrade as an alternative supply to Matawai and some support to Puha. The 11kV line would need to be upgraded along Hihiroroa Road then extended under the 50kV line to the top of Otoko Hill with dog conductor. Earthing, drainage, structures Oil containment for this site are below ENL ‘s current standards.

There is no 50kV transformer protection. A line CB installed at Pehiri is used to clear transformer faults.

Actions
Upgrade / Alterations to this site are allowed for in the development plan.

Patutahi Substation

This substation was constructed by the State Hydro Department in 1929 and at the time was the main supply point to the Gisborne area. The outside bus work is still original but the building was replaced in 1991 as it was constructed out of brick and considered an earthquake risk.

Both transformer banks at the site are ex Transpower banks and are of 1940’s vintage.

In 2000 the 11kV switchgear was replaced with second hand Reyrolle LMT Panels and new vacuum circuit breakers.

The substation comprises

- An incoming 50kV line from Transpower Massey Rd via Makaraka Substation
- An incoming 50kV line from Transpower Massey Rd via Makaraka and Parkinson St
- An Incomer 4 x feeders, 1 x switch/fuse unit.
- An outdoor structure consisting of mostly steel lattice and concrete poles with copper wire bus bar.

Issues

The Earth mat connections need be checked and CAD welded where deteration is identified during an site excavation works.
The switchyard gravel is not up to ENL Zone substation standard.
Oil containment and bunding facilities are required for the transformer banks.
Surge arrestors need to be installed on incoming and outgoing 50KV line, and the old surge arrestors on transformer banks need replaced.
The 50kV CB’s have been identified for replacement.
The single-phase transformer banks have been identified for replacement. One of the 8 units has failed in service and is considered uneconomic to repair.

Actions

A replacement 50kV CB has been purchased. Replacement may be deferred until the major upgrade work is undertaken.

Upgrade work is programmed in the development plan. At this time the substation will be reduced to a single transformer configuration, as the substations at Makaraka and Matawhero are able provide security. The upgrade work addresses all of the issues identified at the site. The Steel lattice bus structure will be eliminated as part of the upgrade.

Pehiri Substation

This substation was built in 1964 when the 50kV ring was built from Puha substation to Patutahi substation. It was recently upgraded in 1998 with a 2.5MW OLTC IMP transformer and PMR SF6 pole mounted CB's using Microtrip protection relays. The Sepa unit was installed 2001. The voltage regulator at the site is used to regulate voltage at 11kV when the transformer is out of service and supply is via the 11kV lines from Patutahi substation.

The substation comprises

- 1 incoming and 1 outgoing 50kV line forming the 50kV ring from Makaraka to Hexton Switching station which also supplies the Patutahi ,Ngatapa and Puha Substations.
- 1 2.5 MVA 50/11kV Transformer
- 1 Voltage Regulator
- 1 11kV Incomer and 4 11kV Feeders on an outdoor bus

Issues

The old 50kV line surge arrestors should be replaced. An old Maier 50kV OCB is still in service.

Economics of the Substation and associated 50kV line are will inhibit any upgrade work at this site. Removal of the Transformer and 11kV supply via the 50kV circuits is being considered. The transformer would be used to replace the single-phase units at Puha substation. If the quarry load disconnects this substation could be eliminated however it would be necessary to maintain the use of the voltage regulator and 11kV switching facilities.

Actions
Nil

Puha Substation

This substation was built in 1960 to feed the rural area of Te Karaka, Whatatutu and Matawai, after several upgrades this substation is still very important for this area. Originally the substation was fed from a single 50kV circuit from Gisborne substation but in 1963 the 50kV ring was installed to Patutahi substation.

In 2000 the transformer bunding and earthing was upgraded. The outdoor 11kV bus and circuit breakers were removed and an ABB Safeplus SF6 switchboard was installed in the existing Concrete block building.

A new 50kV SF6 Merlin Gerin SB6-72 was installed on T1 Transformer bank with 351 protection relay along with new ABB 11kV Safe plus SF6 indoor switch gear and a Multilin F35 protection relay in 2001.

The substation comprises
- 1 incoming and 1 outgoing 50kV line forming the 50kV ring from Makaraka to Hexton Switching station which also supplies the Patutahi ,Ngatapa and Pehiri Substations.
- 1 5.0 MVA 50/11kV Transformer bank (3 units)
- An 11kV switchboard comprising an 11kV Incomer, fuse switch and 4 11kV Feeders.
- A 1MW Diesel Generator Set

Issues

The complete 11kV load from this substation cannot be supplied from any other substation. Supporting Matawai from an upgrade of Ngatapa substation, line extension to Otoko Hill and reinforcing the Lavenham Road feeder from Patutahi is being considered to overcome this situation. 1MW of Diesel generation was installed at the site in 2003 which provides support to within the required security levels for the medium term. Tie capacity from Ngatapa will be developed in the longer term.

The Oil separation facilities have been deferred to coincide with replacement of the transformer bank

Actions
A ring main unit is currently being installed to provide a connection point for the 11kV 1MVA Generator set.

Ruatoria Substation

In 1998 the 50 kV Bus and 4 new PMR SF6 11kV feeder pole mounted circuit breakers with Microtrip relays and 2 overhauled Metrovick 50kV bulk oil circuit breakers were used to upgrade the substation.

In 1999 a new 5/7.5MVA transformer with Bunding an oil facilities was installed. A partial earthing upgrade was carried out as this time.

In order to minimise the yard size and avoid replacement of the dated outdoor 11kV bus and associated earthing a Portacom building and ABB Safe Plus 11kV SF6 switch board was installed in 2001. The earthing and yard surface was upgraded at the same time.

The substation comprises

- 1 incoming 50kV line from Tokomaru Bay Substation
- 1 5.0 MVA 50/11kV Transformer
- An 11kV switchboard comprising an 11kV Incomer, fuse switch, 3 11kV Feeders and 1 Generator connection point..
- A 1MW Diesel Generator Set

Issues:

Nil.

Actions

Nil

Te Araroa Substation

In 1998 the original 11kV switchgear was replaced with second hand Reyrolle LMT panels and new vacuum circuit breakers complete with Mulitin 760 protection relays. An IMP 2.5MVA transformer with OLTC including bunding and oil facilities was also installed. The Sepa unit was added in 2001. The building is concrete block construction.

A Metrovick 50kV bulk oil CB was installed on T1 transformer in 2001 to eliminate the Earth throw switch originally used for transformer protection.

The voltage regulator used for security was removed in 2001 following failure in service.

The substation comprises

- 1 incoming 50kV line from Ruatoria Substation
- 1 2.5 MVA 50/11kV Transformer
- An 11kV switchboard comprising an 11kV Incomer, fuse switch, 3 11kV Feeders and 1 Generator connection point.
- A 1MW Diesel Generator Set

Issues:

The substation load cannot be supported from Ruatoria at 11kV.

Subsidence at the site has caused minor cracks in the building block work. The degree of damage is being monitored.

Actions

Nil

Tokomaru Substation

This substation is adjacent to a now redundant Transpower point of supply.

A new IMP 2.5MVA with OLTC transformer, bunding and was installed in 1998. Earthing was upgraded at the same time. The oil separator was added in 2001.
In 1999 the 11kV switchgear was replaced with second hand Reyrolle LMT panels with new vacuum circuit breakers and Mulitin 760 protection relays. The switch room is concrete block construction.

The substation comprises
- 1 incoming 50kV line from Tolaga Bay Substation
- 1 Outgoing 50kV line to Ruatoria substation
- 1 2.5 MVA 50/11kV Transformer
- An 11kV switchboard comprising an 11kV Incomer, fuse switch and 3 11kV Feeders.
- A 50kV connection to Transpower's Tokomaru Bay Substation. (Not in service)

Issues

Nil

Actions
Nil

Tolaga Bay Substation

Rationalisation of this substation was carried out in 2001. In order to minimise upgrading of the earthing the dated 11kV outdoor bus was removed and the yard size halved. Temporary transformer bunding was installed around the 4 single-phase transformer units. The backup 1.5MVA 50/11kV transformer bank was removed and scrapped. A portable building was installed with an indoor ABB Safeplus SF6 switchboard.
A Metrovick 50kV Bulk oil CB was installed on T1 transformer in 2000.
The earthing for the remaining substation yard was upgraded as part of the project.

The substation comprises
- 1 incoming 50kV line from Goodwin Rd Switching station
- 1 Outgoing 50kV line to Tokomaru Bay Substation
- 1 5 MVA 50/11kV Transformer bank (4 units)
- An 11kV switchboard comprising an 11kV Incomer, fuse switch and 4 11kV Feeders.
- A 1MW Diesel Generator Set

Issues:

The Oil separation facilities have been deferred to coincide with replacement of the transformer bank
11kV support from adjacent substations is within security standards however 200kVA of load cannot be supported without the use of the Diesel generator.

Actions
Nil

Hexton Switching Station

The switching station was installed as part of the project to construct the 2nd 50kV line into Makaraka substation from the Gisborne – Puha circuit in 2001. The switching station consists of a SCADA controlled CB associated Isolator/Earth SW and fence enclosure.
The site is required to prevent faults in the Puha–Ngatapa-Pehiri-Patutahi 50kV sub transmission ring from affecting supply to Makaraka, Matawhero and Parkinson St.

Goodwin Rd Switching Station

The switching station was installed as to prevent faults on the 50kV line from Gisborne to Tokomaru from affecting supply to Kaiti and Port Substations. The switching station consists of a SCADA controlled CB with associated Isolator/Earth SW and fence enclosure. It was constructed in 2002.

Waihi Power Station

The Waihi Power Station is a 5MW hydro power station located off the highway between Frasertown and Tuai.
The station and its assets while owned by ENL are not considered as an integral part of the distribution network and Asset -management is considered separately to this document.

Assets at the site forming part of the Distribution network include the 6.3 MVA 6.6/50kV Transformer and 50kV line from the site.

Oil separation facilities were constructed at the transformer installation in 2001 to minimise risks associated with the adjacent river.

Issues:

Issues relevant to the distribution network related assets are as follows:

Transformer trips activate a phase to phase 50kV throw switch to isolate the 50kV line between Waihi and Kiwi substation.
The Waihi station site is ideally suited to provide an 11kV supply to the immediate area and back feed into the end of the Raupunga and Frasertown 11kV feeders.

Actions

Plans have been developed to rationalise the 50kV line and transformer assets at Waihi with distribution assets solving a number of development issues.

PLANNED REPLACEMENT PROGRAMME

Replacement in relation to zone substation is usually carried out at component level and is addressed in each relevant component section.

GROWTH

Growth is discussed in the load growth analysis section, 50kV lines, 11kV lines and zone transformer sections.

RELIABILITY

This is determined by the equipment in the substation and is discussed in the relevant section.

RISKS

Exposure to faults- Exposure of the substations to feeder faults is common. The combination of high-energy electrical faults and oil fill equipment expose substations to the risk of fire. Metal clad switchgear of modern design is the only defence. Newer equipment no longer contains oil. Sprinkler systems are not a viable option around electrical equipment.
Flooding – Specific issues are identified at Kiwi Substation. In General the current substation designs have switchgear above normal flood levels. Essential outdoor equipment is sealed and electrical bushings and connections are well above flood levels and can operate safely partially submerged.
Earthquake- Essential equipment incorporates earthquake design features as part of standard construction.
Substation failure- In the unlikely event of major substation failure the security standard provides for contingent support capacity from adjacent substations.
Safety- Maintenance programs provide for regular inspection and earth testing at all Zone substations. Defects are corrected in line with the targets identified in the Maintenance section of this plan.

COMPLIANCE ISSUES

Monitoring

Earth testing is carried out 6 monthly at Zone substation sites to monitor any changes to the earth resistance and provide indication of earth mat deterioration.

Three monthly inspections are undertaken to check for damage and confirm equipment operation.

Safety equipment held on sites is minimal and is inspected at intervals not exceeding 7 months.

Oil handling facilities are checked as part of Zone substation inspection and maintenance programs.

Standards

Earthing at Zone substations is carried out in accordance with the codes of practice. In general 70mm2 CU conductor is used with cad-weld connections and copper-clad rods driven at each conductor intersection. The design of the grid is specific to each site and varies depending on soil re-sensitivity factors.

The requirement for bunding is determined by the quantity of oil that could spill in the event of a single rupture. For equipment with low oil quantities less than 200 litres oil spill kits and spill procedures provide for containment and clean-up to minimise environmental damage. Equipment that falls into the low oil quantity category includes switchgear and distribution transformers. For high oil quantities the work comprises, installation of concrete oil containment areas and the installation of oil separators to separate oil from the storm water under normal operating conditions. The requirement for oil containment at a site is dependant on the quantity of oil that could be spilt in any single event.

Gap Analysis

As identified above for issues per Substation

QUALITY AND DEVELOPMENT

Standardisation

New building standards include raised buildings (approx 1 meter) to reduce risk from flooding and allow cable access from underneath.
Where wooden duct covers have been used and have begun to deteriorate they are being replaced with metal covers to reduce fire risks and the chance of failure under load. Alterations carried out on the buildings, as maintenance is required include the removal of windows in buildings where indoor 11kV switchgear is used and replacement of wooden doors and window frames with low maintenance aluminium fittings.

The layout of substation yards has been designed to allow crane access for installation and removal of the large transformer without interference from the overhead 11kV and 50kV lines.

PERFORMANCE ISSUES

Nil identified.

8.A.7 Zone Transformers

DESCRIPTION

There are 19 x 3-phase transformers and 4 x 1-phase transformer banks located across ENL's zone substations. All 50kV/11kV zone substation transformers except Ngatapa T1/T2 are fitted with automatic on load tap-changer equipment.

Zone Substation Transformers			
Location	**Type**	**KVA**	**Manufacture date**
01 Te Araroa Sub	50/11 - 3 Phase	2500	1/01/1998
02 Ruatoria Sub	50/11 - 3 Phase	5000	1/01/1997
03 Tokomaru Bay Sub	50/11 - 3 Phase	2500	8/08/1997
04 Tolaga Bay Sub	50/11 - 1 Phase	1667	1/01/1965
04 Tolaga Bay Sub	50/11 - 1 Phase	1667	1/01/1965
04 Tolaga Bay Sub	50/11 - 1 Phase	1667	1/01/1965
05 Kaiti Sub	50/11 - 3 Phase	12500	1/01/1987
06 Carnarvon Sub	50/11 - 3 Phase	12500	1/01/1971
06 Carnarvon Sub	50/11 - 3 Phase	12750	1/01/1995
07 Parkinson Sub	50/11 - 3 Phase	12500	1/01/1986
08 Makaraka Sub	50/11 - 3 Phase	12750	1/01/2001
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
10 Pehiri Sub	50/11 - 3 Phase	2500	8/07/1996
11 Ngatapa Sub	50/11 - 3 Phase	500	1/01/1930
11 Ngatapa Sub	50/11 - 3 Phase	500	1/01/1930
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
14 Matawhero Sub	50/11 - 3 Phase	5000	1/01/2001
14 Matawhero Sub	50/11 - 3 Phase	5000	14/08/2000
15 Port Sub	50/11 - 3 Phase	12750	1/01/2001
31 TPWairoa Sub	33/11 - 3 Phase	2500	1/01/2000
32 Kiwi Sub	50/11 - 3 Phase	6300	1/01/1983
33 Blacks Pad Sub	33/11 - 3 Phase	1500	14/05/2000
34 Tahaenui Sub	33/11 - 3 Phase	1500	14/05/2000
35 Waihi Sub	50/11 - 3 Phase	6300	1/01/1983

LIFE ASSESSMENT

The general expectation for transformer life is 60 years if the load has generally been low and overhaul work has been undertaken at 30 years alternatively 45 year life is expected if no life extension work has been carried out.

Zone transformers are considered critical equipment as the lead-time for replacement or repair can be months and they are generally too expensive to warrant holding spares. For this reason it is important that they are replaced before there is any risk of in-service failure.

Data Source

Industry Model adjusted to ENL's experience. Assumes maximum ODV life of 60 years is attained.

Replacement Trigger

Replacement transformers need to be ordered 2 years ahead of the expected end of life to provide a contingency against premature failure. Single-phase banks are not economic to overhaul and therefore are limited to 45 years service.

Transformers with a history of poor oil condition or high loading are to be replaced early as assessed by DGA.

PLANNED REPLACEMENT PROGRAMME

As Zone transformers are considered critical assets the replacement program has been determined by consideration of each individual Transformer covering External and internal condition, History of operation, Current needs, losses, and age.

Significant new installations are required and these are coordinated with changes at existing substations. The action plan given in the growth section includes age replacements, removals and new substations. In general new substations are the preferred solution to providing new capacity.

Summary of Actions

Year	Action	Cost
2008/2009	Replace T1 at Tolaga with 1x 2.5MVA 3-Phase	$500,000
2009/2010	Replace T1 and T2 Patutahi with 1x 5MVA 3-Phase	$500,000
2012/2013	Replace T1 Puha with 1x 5MVA 3-Phase	$250,000

Costs include all items associated with project

GROWTH

Constraints and Triggers

Zone substations are designed to support one another in the event of an outage. Therefore not only is a zone transformer sized to allow for a minimum of 10 years growth it must also have sufficient capacity to supply 11kV contingency capacity to its neighbouring substations.

When a transformer exceeds its spare capacity for load growth then it will be permitted to provide contingency capacity by operating at 120% on an 8 hour duty cycle provided temperature is kept below 65°C. For every year the transformer is operated at nominal full load its life will be reduced by 3 years.

Forecasts for Growth/Security

Load growth and shifting load centres has been described in Section 5.0. The following schedule of actions lists predicted substation/transformer capacity upgrades including new installations. Cost estimates assume associated substation developments/equipment included.

Summary of Actions

Year	Action	Cost
2004/2005	T2 12.5MW Parkinson	$536,000
2004/2005	New 12.5MW Sub JNL	$1,000,000
2005/2006	Mahia 2.5MW ex-Wairoa Upgrade Wairoa to 5/7MW	$700,000
2007/2008	Upgrade 2.5MW T1 Ngatapa	$700,000
2014/2015	T1 2.5MW and new sub at Tatapouri	$850,000
2016/2017	T1 12.5MW and new sub at Mangapapa	$1,200,000

Costs include all items associated with project

RELIABILITY AND SERVICE

Standard

- Nil in service failures.
- Condition, age, etc. to be maintained at a level where risk of failure is maintained at bottom of the reliability “bath tub” curve.

Justification

Repairs and replacements cannot be affected in any reasonable timeframe.

Criticality

Failure of a single unit generally causes the greatest impact on customer minutes due to the large customer numbers involved.

The zone substation transformer assets are considered the most critical assets in terms of the reliability of supply.

Gap Analysis

Transformers have a nominal 45 year life unless condition assessment indicates that they are aging at a slower rate than industry experience. Aging is related to loading and maintenance. If condition is confirmed good and a full overhaul is undertaken life can be extended to a maximum of 60 years.

Tap changers are the weak link in transformer reliability. ENL carries a spare OLTC unit for its IMP transformers, which have proven to be less reliable if full rebuild isn't undertaken on delivery to ensure quality of fitting. A range of other spares such as bushings are also carried.

There is a surplus of single phase units currently in service for the single phase transformer banks. Therefore a number of units can be allowed to fail in service before total replacement is required.

Dual transformer installations can also avoid early replacement due to the higher security provision.

Summary of Actions

Transformers due for major overhaul at $30,000.

Carnarvon T1	2004/2005
Kaiti T1	2016/2017
Parkinson T1	2016/2017

This work is intended to justify life extension from 45 years to 60 years and is therefore capitalised.

COMPLIANCE ISSUES

Monitoring

Voltage monitoring 11kV tap changers within regulations monitor via SCADA.

Standard

- New transformers require secondary oil containment and oil separation equipment per District Plan.
- Earthquake mountings are required to have engineering certification. Connections to bushings are also designed for earthquake tolerance.
- PCB free oil tests.
- Noise standards per District Plan

Gap Analysis

A program of installing Bunding around existing transformers in is place despite it not being compulsory to retrofit Bunding for compliance with the District Plan. This is because there is still an obligation and liability for cleaning up if a spill occurs.

Transformers unable to be substantiated by documented earthquake design calculations as being adequate require upgrading/substantiating.

Summary of Actions (Oil Containment)

Parkinson Street Bunding and separator to coincide with new T2 unit	2004/2005
Carnarvon Street T2 Bunding to coincide with Overhaul	2004/2005
Patutahi Bunding and separator included with Transformer replacement	2009/2010
Puha separator included with Transformer replacement	2012/2013
Tolaga separator included with Transformer replacement	2008/2009
Ngatapa Bunding + separator included with Transformer replacement	2007/2008
Kiwi Bunding separator included with Rationalisation Project	2007-2009

Actions Earthquake restraints

Parkinson Street T1 to coincide with new T2 unit
Carnarvon Street T2 to coincide with refurbishment
Kaiti T1 to coincide with refurbishment

QUALITY AND DEVELOPMENT

Standardisation

Standard incremental sizes used on the network are 2.5, 5/7, 12.5MVA.

The purchase of low cost IMP transformers from India with on site supervision of the construction has proved successful to date. Continued purchases are planned in future.

Alterations carried out on the initial IMP design that are now incorporated into new purchases include:

- Anti vibration pads between transformer and concrete pad
- Separate tap changer and transformer oil compartments in conservator tanks.
- Pressure relief valves in addition to the Buchholtz fitted to both the transformer and tap changer.
- Less than 1.5% transformer losses
- A spare tap changer is held for contingency purposes.

Transformers are most efficient when operating close to full load. The 10 year capacity for growth provides a good compromise between matching load to demand and not having to upgrade transformers too frequently.

New Technology / Innovations

As opportunity permits new transformer purchases in rural locations will comprise smaller capacity 3-phase units, which allow compact substation design and reduced maintenance over the life of the units. Contingency capacity of neighbouring subs needs to be reassessed in order to compensate for the reduction in spare capacity traditionally provided by the fourth spare unit in a single phase transformer bank.

In the coastal regions east of Gisborne introduction of multiple low capacity 50/11kV transformer installations is planned to provide a more cost effective solution for the regions growth rate as the need to upgrade 11kV capacity is eliminated and the cost of incremental capacity increases is lower than the traditional zone substation approach. As a number of the coastal zone substation installations have been renewed over the last 3 years implementation of the new design will be deferred until the assets can be redeployed.

PERFORMANCE ISSUES

Known performance issues and past events that have limited transformer life include the following: -

Ngatapa
The transformers at this substation are the oldest units still in service and test results indicate replacement is due.

Patutahi
Blue phase transformer on T2 bank has a low test, but it is to be removed from service if it fails.

Puha
The alternative to defer T1 replacement is to install a new transformer at Ngatapa, improving the security support to Puha and reducing the area affected in the event of an outage

Tolaga
The T1 transformer bank has had a major overhaul in 1996.

8.A.8 Circuit Breakers

DESCRIPTION

Automatic switchgear is used for fault isolation, protection of critical equipment and sectionalisation of the network. This includes reclosers, sectionalises, fault indicators, fuses and links. This equipment is considered as a group because a system design approach is applied to obtain a co-ordinated protection scheme.

The types and quantities of Circuit Breakers installed on the network are summarised in the following table.

Description	Type	Quantity
50 kV Circuit breakers	Oil	11
	SF6	16
11 kV Circuit Breakers	Oil	35
	Oil/Vacuum	7
	SF6	55
	SF6/Vacuum	20
	Vacuum	37

Types of 50kV CBs used include outdoor Bulk Oil, Minimum Oil and SF6. The older CB designs require compressed air systems for closing. The newer designs use spring charge mechanisms with either 110 or 24 Volt DC motors.

Application of each CB type depends on the fault levels and clearing times required. In a line protection application the circuit breakers are used to sectionalise faults on the long rural 50kV lines reducing the number of zone substations affected. When used to protect zone substation transformers high reliability and faster clearing times are required to minimise potential damage to the transformers in the event of a fault.

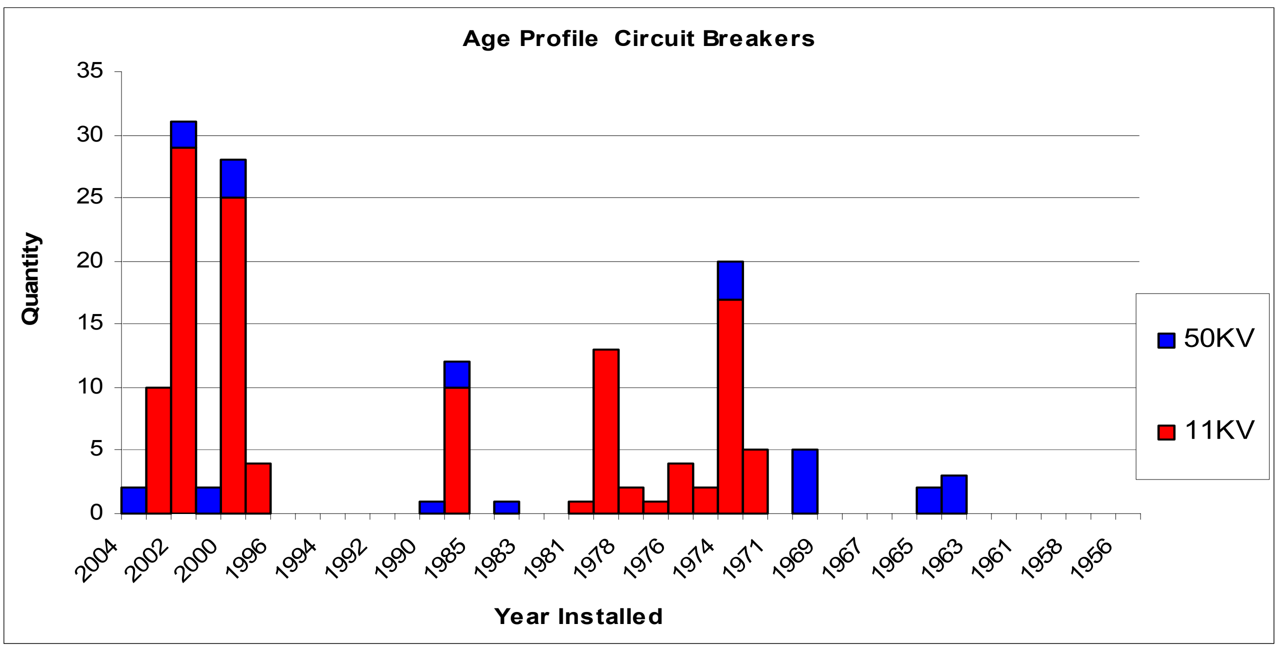
At zone substations where no 50kV CB's are used to protect the transformers the line CB’s are also used to clear the remote transformer faults in conjunction with earth fault throwing switches triggered by the transformer protection. This design is used where the transformers are older (more robust construction), have a capacity below 3MW, the fault levels are below 1000amps, and the 50kV line is longer than 10km.

Because fast clearing times are not required the older Minimum Oil CB's with slower operating characteristics are used for line protection. At single transformer substations where 50kV earth fault throwing switches are used for 50kV protection 11kV incomer CBs are installed to provide the backup feeder protection functions and transformer overload protection. Where 50kV incoming breakers are installed 11KV switches are considered adequate in place of the 11kV incomer CB's and are used for transformer isolation purposes.

Both indoor and outdoor configurations are used for 11kV Circuit Breakers. Various types used include outdoor pole mounted vacuum/oil or SF6 reclosers, outdoor minimum oil circuit breakers, outdoor pole mounted oil sectionalisers and indoor vacuum or SF6 circuit breakers which rack into cubicles.

LIFE ASSESSMENT

ODV Standard Life	40 years
Population size	181
Start of failure period	35years
Failure period	10years
Average residual quantity	1
Average installation quantity	4/yr
Targeted replacement rate	6/yr
Rate of growth/security additions	1/yr



Age Profile Comments

Data includes all 50kV, 11kV, indoor and pole mounted equipment. There is insufficient population of any single type to draw conclusions. The period from 1999 to 2004 reflects rural CB installation and Zone substation upgrading programmes.

11kV switchboard reliability is critical and therefore early replacement is desirable.

The 50kV Bulk Oil CB's were obtained 2nd hand from Transpower and refurbished. Prior to installation they were 40 to 50 years old and based on current assessment replacement of these units will be necessary between 2008 and 2011 as the insulation of the equipment begins to fail. The refurbished units are used in locations where the peak load does not exceed 10MW, fault levels are low to ensure maximum life extensions are obtained, and slow clearing times are acceptable.

Replacement Criteria

Replacement of CB's is justified on the basis of maintenance savings and risks of failure. The cost of major refurbishment overhauls of the CB's has been in the order of 25% of a new unit giving an expected 25% life extension. This has allowed the CB replacement program to be managed over a more controlled timeframe. More recently new CB costs have reduced hence refurbishment is now uneconomic by comparison with life expectancies.

PLANNED REPLACEMENT PROGRAMME

50 kV Circuit Breakers

Location		Make	Manuf Date	Refurbished .	Replace
Te Araroa	T1	Bulk Oil Metro Vic	1952	1997	2008
Ruatoria	T1	Bulk Oil Metro Vic	1952	1997	2010
	Line to TeAraroa	Bulk Oil Metro Vic	1953	1997	2010
Tokomaru	T1	Bulk Oil Metro Vic	1952	1996	2011
	Line to Ruatoria	Bulk Oil Metro Vic	1949	1996	2011
	Line to Tolaga	Bulk Oil Metro Vic	1949	1996	Remove
Tolaga	T1	Bulk Oil Metro Vic	1952	1999	2008
Kaiti	T1	Sprecher Sh SF6	1987	-	2027
Port	T1	Schnider SF6	2003		2043
Carnarvon	T1	Reyrolle Min Oil	1974	-	2014
	T2	AEG SF6	1986	-	2026
	Bus	Schnider SF6	2004		2044
Parkinson	T1	Sprecher Sh SF6	1986	-	2026
Makaraka	Line to Patutahi	Reyrolle Min Oil	1974	-	2014
	Line to Parkinson	Sprecher Sh SF6	1990	-	2030
	Inject Plant	Reyrolle Min Oil	1974	-	2014
	Line to Matawhero	Schnider SF6	2000	-	2040
	T1	Sprecher Sh SF6	1990	-	2030
Matawhero	T1	Schnider SF6	2000	-	2040
	T2	Schnider SF6	2002		2042
	Bus	Schnider SF6	2004		2044
Hexton	Line to Puha	Schnider SF6	2001	-	2041
Goodwin Rd	Line to Tolaga	Schnider SF6	2002		2042
Puha	T1	Schnider SF6	2001	-	2041
Patutahi	T1 & T2	Mitsubishi Bulk Oil/ Air	1968	1995	2005
	Line to Pehiri	Mitsubishi Bulk Oil/ Air	1968	1995	2005
Pehiri	Line to Ngatapa	Maier Bulk Oil	1937	1996	2005

.

11 kV Circuit Breakers

Location	Make	Model	YEAR	REPLACE
01 Te Araroa Sub	Reyrolle	LMVP	1998	2038
01 Te Araroa Sub	Reyrolle	LMVP	1998	2038
01 Te Araroa Sub	Reyrolle	LMVP	1998	2038
01 Te Araroa Sub	Reyrolle	LMVP	1998	2038
01 Te Araroa Sub	Reyrolle	LMVP	2003	2043
0102 Hicks Bay	Hawker Siddeley	PMR Microtrip 11kV	1997	2037
02 Ruatoria Sub	ABB	Safeplus	2002	2042
02 Ruatoria Sub	ABB	Safeplus	2002	2042
02 Ruatoria Sub	ABB	Safeplus	2002	2042
02 Ruatoria Sub	ABB	Safeplus	2002	2042
02 Ruatoria Sub	ABB	Safeplus	2002	2042
0206 Tiki Tiki	Hawker Siddeley	PMR Microtrip 230	1997	2037
0206 Tiki Tiki	Hawker Siddeley	PMR Microtrip 230	1997	2037
03 Tokomaru Bay Sub	Reyrolle	LMT	1999	2039
03 Tokomaru Bay Sub	Reyrolle	LMT	1999	2039
03 Tokomaru Bay Sub	Reyrolle	LMT	1999	2039
03 Tokomaru Bay Sub	Reyrolle	LMT	1999	2039
0301 Inland	Hawker Siddeley	GVR Polar	2002	2042
0302 Seaside	Whipp and Bourne	GVR 351P	2000	2040
0304 Mata	Whipp and Bourne	GVR 351P	2000	2040
0304 Mata	Coopers	KFE	1974	2014
04 Tolaga Bay Sub	ABB	Safeplus	2002	2042
04 Tolaga Bay Sub	ABB	Safeplus	2002	2042
04 Tolaga Bay Sub	ABB	Safeplus	2002	2042
04 Tolaga Bay Sub	ABB	Safeplus	2002	2042
04 Tolaga Bay Sub	ABB	Safeplus	2002	2042
0404 Tauwhareparae	Hawker Siddeley	PMR Microtrip 11kV	1997	2037
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
05 Kaiti Sub	Merlin Gerin	Fluarc FG	1987	2027
0502 Dalton	Hawker Siddeley	GVR Polar	1998	2038
0502 Dalton	Whipp and Bourne	GVR 351P	2000	2040
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014

06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
06 Carnarvon Sub	Reyrolle	LMT	1974	2014
0602 City	ABB	Safeplus	2002	2042
0602 City	ABB	Safeplus	2002	2042
0602 City	ABB	Safeplus	2002	2042
0602 City	ABB	Safeplus	2002	2042
0603 Reads Quay	Reyrolle	LMT	1976	2016
0603 Reads Quay	ABB	Safeplus	2002	2042
0607 Gladstone	ABB	Safeplus	2002	2042
0608 Palmerston	ABB	Safeplus	2002	2042
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
07 Parkinson Sub	Merlin Gerin	Fluarc FG	1986	2026
08 Makaraka Sub	Reyrolle	LMVP	2002	2042
08 Makaraka Sub	Reyrolle	LMVP	2002	2042
08 Makaraka Sub	Reyrolle	LMVP	2002	2042
08 Makaraka Sub	Reyrolle	LMVP	2002	2042
08 Makaraka Sub	Reyrolle	LMVP	2002	2042
0803 Nelson	GEC	CB	1978	2018
0804 Haisman	GEC	CB	1978	2018
0805 Bushmere	Whipp and Bourne	GVR 351P	2000	2040
0805 Bushmere	Whipp and Bourne	GVR 351P	2000	2040
0805 Bushmere	Whipp and Bourne	GVR 351P	2000	2040
09 Patutahi Sub	Reyrolle	LMVP	2000	2040
09 Patutahi Sub	Reyrolle	LMVP	2000	2040
09 Patutahi Sub	Reyrolle	LMVP	2000	2040
09 Patutahi Sub	Reyrolle	LMVP	2000	2040
09 Patutahi Sub	Reyrolle	LMVP	2000	2040
0905 Muriwai	Hawker Siddeley	PMR Microtrip 230	1997	2037
0906 Te Arai	Hawker Siddeley	PMR Microtrip 230	1997	2037
10 Pehiri Sub	Hawker Siddeley	PMR Microtrip 230	1997	2037
10 Pehiri Sub	Hawker Siddeley	PMR Microtrip 230	1997	2037
10 Pehiri Sub	Hawker Siddeley	PMR Microtrip 230	1997	2037
10 Pehiri Sub	Hawker Siddeley	PMR Microtrip 230	1997	2037
10 Pehiri Sub	Hawker Siddeley	PMR Microtrip 11kV	1997	2037
1003 Tiniroto	Hawker Siddeley	PMR Microtrip 230	1997	2037
1003 Tiniroto	Whipp and Bourne	GVR 351P	2000	2040
11 Ngatapa Sub	Whipp and Bourne	GVR 351P	2000	2040
11 Ngatapa Sub	Whipp and Bourne	GVR 351P	2000	2040
11 Ngatapa Sub	Whipp and Bourne	GVR 351P	2000	2040
11 Ngatapa Sub	Whipp and Bourne	GVR 351P	2000	2040
1103 Tahora	Hawker Siddeley	PMR Microtrip 230	1997	2037

12 Puha Sub	ABB	Safeplus	2002	2042
12 Puha Sub	ABB	Safeplus	2002	2042
12 Puha Sub	ABB	Safeplus	2002	2042
12 Puha Sub	ABB	Safeplus	2002	2042
12 Puha Sub	ABB	Safeplus	2002	2042
1201 Whatatutu	Whipp and Bourne	GVR 351P	2000	2040
1204 Matawai	Whipp and Bourne	GVR 351P	2000	2040
1204 Matawai	Whipp and Bourne	GVR 351P	2000	2040
1204 Matawai	Coopers	KFE	1974	2014
14 Matawhero Sub	Motopol	CB11	2000	2040
14 Matawhero Sub	Motopol	CB11	2000	2040
14 Matawhero Sub	Motopol	CB11	2000	2040
14 Matawhero Sub	Motopol	CB11	2000	2040
14 Matawhero Sub	Motopol	CB11	2003	2040
14 Matawhero Sub	Motopol	CB11	2003	2040
14 Matawhero Sub	Motopol	CB11	2003	2040
14 Matawhero Sub	Motopol	CB11	2003	2040
15 Port Sub	Reyrolle	LMVP	2003	2043
15 Port Sub	Reyrolle	LMVP	2003	2043
15 Port Sub	Reyrolle	LMVP	2003	2043
15 Port Sub	Reyrolle	LMVP	2003	2043
15 Port Sub	Reyrolle	LMVP	2003	2043
2003 Ruakituri	Coopers	KYLE 3H	1973	2013
2003 Ruakituri	Coopers	KYLE 3H	1973	2013
2003 Ruakituri	Coopers	KFE	1979	2019
31 TPWairoa Sub	Hawker Siddeley	GVR Polar	1998	2038
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
32 Kiwi Sub	GEC	FMX	1980	2020
3201 Raupunga/Brickworks	Coopers	KF	1973	2005
3201 Raupunga/Brickworks	Coopers	KYLE 3H	1974	2005
3201 Raupunga/Brickworks	Coopers	KYLE 3H	1976	2005
3201 Raupunga/Brickworks	Coopers	KFE	1980	2020
3201 Raupunga/Brickworks	Coopers	KFE	1981	2021
3203 Frasertown/Nuhaka	Coopers	KF	1973	2005
3203 Frasertown/Nuhaka	Coopers	KF	1974	2005
3203 Frasertown/Nuhaka	Coopers	KYLE 3H	1975	2006
3203 Frasertown/Nuhaka	Coopers	KYLE 3H	1975	2006
3203 Frasertown/Nuhaka	Coopers	KYLE 3H	1976	2006
3203 Frasertown/Nuhaka	Coopers	KYLE 3H	1977	2006
3203 Frasertown/Nuhaka	Coopers	KFE	1980	2020
3203 Frasertown/Nuhaka	Coopers	KFE	1980	2020
3203 Frasertown/Nuhaka	Hawker Siddeley	GVR Polar	2002	2042
33 Blacks Pad Sub	Whipp and Bourne	GVR 351P	2000	2040
3301 Mahia	Coopers	KF	1972	2006

3301 Mahia	Coopers	KF	1973	2006
3301 Mahia	Coopers	KYLE 3H	1974	2006
3301 Mahia	Coopers	KYLE 3H	1976	2006
34 Tahaenui Sub	Whipp and Bourne	GVR 351P	2000	2040

GROWTH

Constraints and Triggers

The standard CB ratings are:

1250 A	Incomer on Bus CB rating large substations
650 A	Normal substation feeder CB used for Incomer on smaller substation
400 A	Minimum CB rating used for rural substations or remote reclosers

To accommodate growth ratings are selected on the basis that the CB rating is twice the normal feeder load. This is a contingency provision to allow a CB to carry the load of its adjacent feeder as needed for maintenance outage.

The most significant constraint on feeder CB's currently is the rating of the feeder cables connected to the CB's.

Where feeders are used for ties to other substations, capacity is allowed for this load in addition to normal CB loading.

Short time fault ratings for CB's range from 12 kA to 21 kA, which is within the current fault levels at all, substations.

Loads on older 50kV CB's restricted to 10MW peak are not expected to exceed the restriction prior to the planned CB replacement dates.

Summary of Actions

.
A number of new 50kV CB’s will be required to implement N-1 protection for the Carnarvon, Kaiti, Port sub-transmission ring and the Makaraka Matawhero, Parkinson sub-transmission ring. These costs are included in the project costs. Refer Network Development.

RELIABILITY AND SERVICE

Standard

Indoor installations are justified in urban substations to allow compact substation design and reduced risk of damage or faults from external interference. Indoor switchboards are configured with Bus Section circuit breakers where dual transformer configurations are installed.

For 50kV CB’s where it is not possible to maintain supply when switchgear is taken out of service for maintenance bypass arrangements are an integral part of the design. In general at the larger urban substations alternative supplies are available via the 2nd transformer banks, adjacent substations, and 11kV feeders, therefore bypass arrangements are not required.

Criticality

Indoor bussed switchgear is considered critical as in a majority of zone substations there is only N security and failure usually attracts long repair times.

Gap Analysis
No current issues

COMPLIANCE ISSUES

Oil quantities associated with CB’s are low in comparison with the zone substation transformers. Oil spills are managed with oil handling procedures and Oil spill kits suitable for the volumes of oil are held at each zone substation as a contingency.
New regulations have introduced a certificate of compliance regime for all pressure vessels greater than 70 psi. The pressure system and age of components used in the system for the air operated 50kV Circuit breakers at Patutahi makes early replacement desirable.

Monitoring

Testing is undertaken during maintenance checks.

Standard

Insulation must test at greater than 15 GOhm.

Bulk oil circuit breakers are located within bunded containment areas.

Oil spill kits and handling procedures are located at all zone substations to cope with oil spills from circuit breakers with lower oil quantities.

Insulation levels are maintained within the manufacturer's specifications and are measured with discharge monitoring equipment or during servicing.

Gap Analysis

The bulk oil 50kV CB's at Ruatoria, Tokomaru, Tolaga and Te Araroa do not have oil containment facilities. These breakers will not be replaced with bulk oil equivalents.

Required Outcome

Correction of existing issues will be complete by 2011 and arising issues will be corrected within 5 years.

QUALITY AND DEVELOPMENT

Outdoor CB's used for all 50kV applications.

Indoor 11kV circuit breakers used for all Substations where multiple feeders are necessary.

Bypass and isolation arrangements are installed for 50kV CB's where no alternative supply is available.

Incomer and bus section configurations are used where dual transformer configurations exist.

All circuit breaker/feeder ratings are twice the normal feeder load to allow support of adjacent feeder loads.

Standardisation

50 kV Circuit Breakers

New 50kV CB purchases have been standardised for compatibility and reduced long term costs. Standard features include:

- SF6 outdoor
- 66kV rated minimum
- DC 24 volt operation (reduces 110V DC battery costs currently incurred due to older CB designs)

11kV Circuit Breakers

- Min 400A rating and 12kA short time fault rating
- SF6 or Vacuum
- Indoor configurations for multiple feeder substations.
- Bursting discs fitted to outdoor reclosers (requirement from previous failure issues)
- Electronic protection with fully configurable curve types and settings including DNP3 or Modbus communications capabilities.
- 24v DC operating mechanisms
- Live line installation standard with bypass features using hot stick techniques
- SCADA control fitted to all remote recloser installations.
- Inclusion of Fault locators into recloser and protection schemes is also planned to optimise the overall network performance
- Co-ordination density criteria CB's reclosers and sectionalisers, fuses, fault indicators.
- Feeder CB per each substation feeder
- Field CB not more than 2 cascaded from Feeder CB
- Sectionaliser not more than 1 cascaded from Field CB
- Fuses Branch fusing on private spur lines

- Fault indicators fitted to unfused branch or spur lines with more than 30 customers or connected network exceeds 10km.

New Technology

Automation of all 50kV line isolators to minimise restore times. Motorised automation of switches facilitates their use for sectionalising and tie purposes
Fault indicators are to be used in conjunction with switchgear to aid fault finding
Implementation of live-line design, to facilitate switchgear maintenance and replacement, without supply interruptions.

Summary of Actions

A rural protection and automation development plan has been created to address:

- Protection coordination
- Improve performance
- Replace existing aging equipment and correct existing issues
- Substitute requirement to replace ABS's, fuses, etc, i.e. use less new technology to replace older solutions.

This Plan identifies the optimum solution for each location, i.e. recloser, sectionaliser, Automatic Switch, fault indicator, fuses, etc and is therefore coordinated across all these asset types.

The current program for implementation of the plan is as follows:

Description	Location	Year	Cost
Install PMR Brush 230V Close EX Ruatoria		2004/2005	$16,310
New Automatic Switch	Puhanga Rd SH35 Crn (J33)	2004/2005	$22,810
New Automatic Switch	Makariki Rd by Makarika School (H71)	2004/2005	$22,810
New Automatic Switch	Ihungia Rd SH35 Crn (H61)	2004/2005	$22,810
New Automatic Switch	Tuakau Rd Mata Rd Crn (H135)	2004/2005	$22,810
New Automatic Switch	Mata Rd Tuakau Rd Crn (H164)	2004/2005	$22,810
New Automatic Switch	Riverside Rd Goodwins Rd Crn	2004/2005	$22,810
New Automatic Switch	Kanakanaia Rd Bruce Rd	2004/2005	$22,810
New Automatic Switch	Tarndale Rd Armstrong Rd Crn	2004/2005	$22,810
New Automatic Switch	Pehiri Rd Before End	2004/2005	$22,810
New Automatic Switch	Woodlands	2004/2005	$22,810
Upgrade SCADA	Opatama	2004/2005	$9,900
Upgrade SCADA	Iwitea Rd	2004/2005	$9,900
Upgrade SCADA	Whakaki	2004/2005	$9,900
Upgrade SCADA	Kotemaori	2004/2005	$9,900
Upgrade SCADA	Waihua	2004/2005	$9,900
New Automatic Switch	Clydebank	2004/2005	$22,810
			$316,720
Install PMR Brush 11KV Close EX Puha	Waikura Valley Rd	2005/2006	$16,310
AUTOMATE VREG	Waingake Rd near School	2005/2006	$9,900
New Automatic Switch	Taumata Rd Wharekopae Rd Crn	2005/2006	$22,810

New Automatic Switch	SH2 Olivers Rd Rakauroa	2005/2006	$22,810
New Automatic Switch	Whakarau Rd Olivers Rd Crn	2005/2006	$22,810
Upgrade KFE and SCADA	Oraka	2005/2006	$18,100
Upgrade SCADA	Blacks Corner	2005/2006	$9,900
Upgrade SCADA	Mahunga Spur	2005/2006	$9,900
Upgrade SCADA	Morere	2005/2006	$9,900
Upgrade SCADA	Te Marie	2005/2006	$9,900
Upgrade SCADA	Waihi Rd	2005/2006	$9,900
Upgrade SCADA	Raupunga	2005/2006	$9,900
New Automatic Switch	Kahungungu	2005/2006	$22,810
New Automatic Switch	Waihua Valley	2005/2006	$22,810
Remove Sectionaliser	Awamate	2005/2006	0
New Automatic Switch	Frasertown	2005/2006	$22,810
			$240,570
New Automatic Switch	East Cape Rd Te Araroa	2006/2007	$22,810
New Automatic Switch	Ardkeen	2006/2007	$22,810
New Automatic Switch	Waitai Valley	2006/2007	$22,810
New Automatic Switch	Muhanga	2006/2007	$22,810
New Automatic Switch	Pokopoko-Ardkeen	2006/2007	$22,810
New Automatic Switch	Maungataniwha	2006/2007	$22,810
New Automatic Switch	Ruakituri	2006/2007	$22,810
New Automatic Switch	Ruakituri	2006/2007	$22,810
New Automatic Switch	Ohuka	2006/2007	$22,810
			$205,290
Install Recloser ex Ngatapa	TBA	2007/2008	$16,000
Install Recloser ex Ngatapa	TBA	2007/2008	$16,000
Install Recloser ex Ngatapa	TBA	2007/2008	$16,000
Install Recloser ex Ngatapa	TBA	2007/2008	$16,000
Automate RMU	Ormond Rd Haisman Rd Corner	2007/2008	$12,000
Automate Switch Gear	Gisborne Hospital	2007/2008	$12,000
			$88,000
Fault Locators with SCADA indication	4 of various	2004/2005	$10,000
Fault Locators with SCADA indication	20 of various	2005/2006	$50,000
Fault Locators with SCADA indication	24 of various	2007/2008	$60,000

PERFORMANCE ISSUES

11kV CB's are very reliable the main issue relating to their reliability is the co-ordination of protection settings. The lack of standardisation of older units with built in protection makes it difficult to co-ordinate protection with newer devices resulting in inferior performance. With faster clearing times and more devices requiring discrimination older mechanical equipment often cannot meet the need for steeply inverse characteristics.

Alteration or replacement of the KYLE reclosers to provide earth fault protection is also necessary for rural protection co-ordination to be successful.

Rural protection and automation has already been achieved in Wairoa. However performance of the original equipment still in use is severely limited by:

- Poor communications related to aerial/cable design and condition
- System DO RTU's which have proven to be inadequately robust for rural conditions
- Mixing old equipment retro fitted new automation
- Poor actuator design
- Battery life
- Lack of protection coordination

Correction of the issues is incorporated into the Automation project.

8.A.9 Distribution Transformers

DESCRIPTION

The following table indicates the approximate quantities of distribution transformers used on the network.

Description	Quantity
Distribution Transformer Cable Entry 11/0.4 kV 1 Ph up to 30 kVA	3
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 100 kVA	19
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 1000 kVA	15
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 1500 kVA	2
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 200 kVA	90
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 300 kVA	211
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 500 kVA	45
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph 750 kVA	1
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph Up to 30 kVA	20
Distribution Transformer Cable Entry 11/0.4 kV 3 Ph100 kVA	50
Distribution Transformer Pole Mounted 11/0.4 kV 1 Ph 30 kVA	134
Distribution Transformer Pole Mounted 11/0.4 kV 1 Ph 75 kVA	1
Distribution Transformer Pole Mounted 11/0.4 kV 1 Ph Up to 15 kVA	836
Distribution Transformer Pole Mounted 11/0.4 kV 1 Ph Up to 15 kVA	9
Distribution Transformer Pole Mounted 11/0.4 kV 3 Ph 100 kVA	73
Distribution Transformer Pole Mounted 11/0.4 kV 3 Ph 200 kVA	14
Distribution Transformer Pole Mounted 11/0.4 kV 3 Ph 300 kVA	8
Distribution Transformer Pole Mounted 11/0.4 kV 3 Ph 50 kVA	215
Distribution Transformer Pole Mounted 11/0.4 kV 3 Ph Up to 30 kVA	1748
Voltage Regulator 11/11 kV 3 Ph 1500 kVA	1
Voltage Regulator 11/11 kV 3 Ph 750 kVA	8
	3503

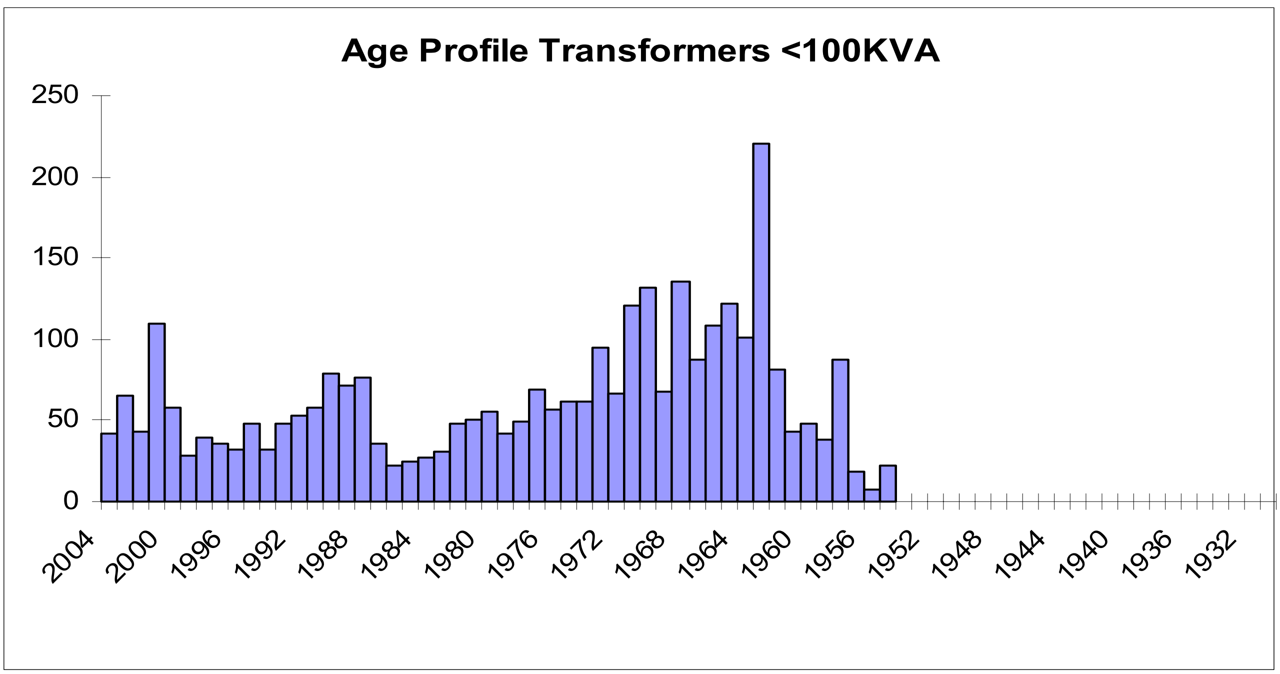
Included in this category 9 voltage regulator installations at:

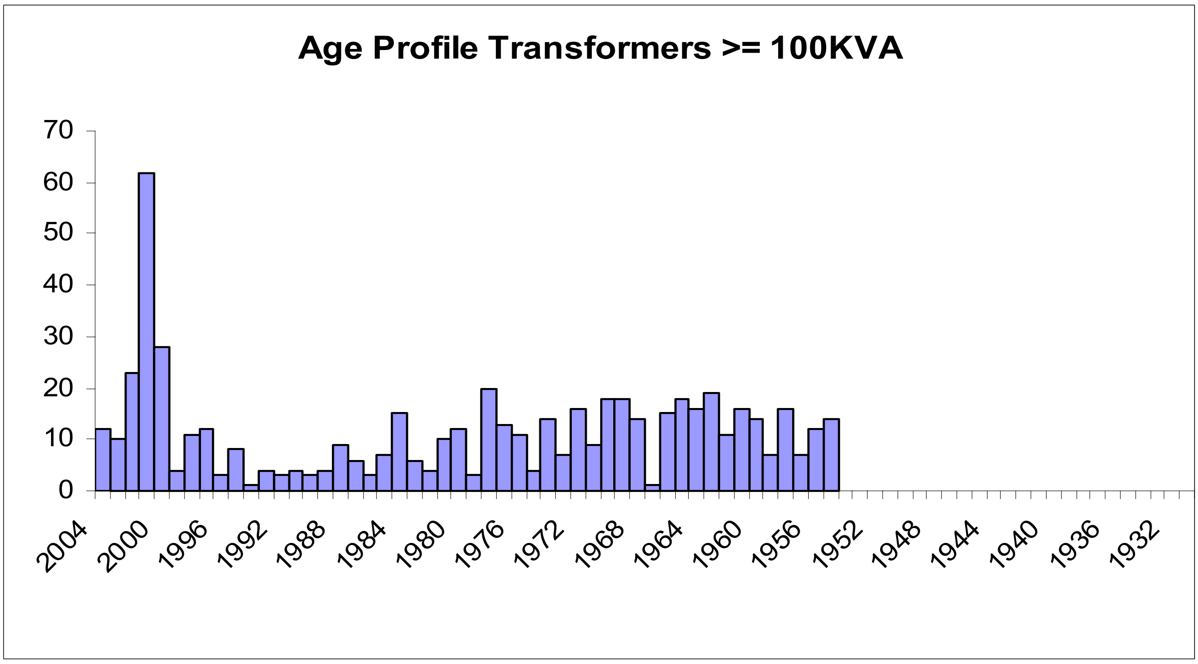
- Pehiri substation - security of supply contingency
- Kopuaroa between Ruatoria and Tokomaru for security of supply contingency
- Tatapouri between Kaiti and Tolaga for distance boost
- Ngatapa substation – no tap changers
- Matawai – distance boost required due to length of feeder
- Waingake – to support water works
- Nuhaka - distance boost
- Waihua for Raupunga feeder distance boost
- Mahia – distance boost

The Nuhaka regulator is an MacGraw Edison auto-booster which boosts the outside 2 phases asymmetrically relative to the centre phase.

LIFE ASSESSMENT

ODV Standard Life		45 years
Population Size		3503
	Small	Large
Start of failure period	38 years	45 years
Failure Period	10 years	5 years
Average Residual Quantity	10	1
Average Installation Quantity	70 per year	13 per year
Targeted Replacement Rate	50	12
Rate of Growth Additions	30	6





Age Profile Comments

Transformers have a reasonably fast roll-off in survival spanning a 5-10 year period indicating sudden total failure mechanisms (e.g. tank rusting through)

A large installation of 200 small transformers remains installed in 1962. This peak is reducing as replacement continues.

Large transformers (>=100kVA) have an even installation profile. On average 12 were installed per year from 1960-1985, and 5/yr after 1985- 2000.

The Compliance program in 2000 eliminated the majority of the older group of pole mounted 250kVA units.

Transformers have been in a replacement cycle since 1988 at an average rate of 60/yr. This is estimated to comprise of 40 normal annual failures, movements and/or new transformers plus 20 age related replacements.

Residual survival is considered negligible as it is only evident in large transformers reflecting the maintenance attention they are likely to have received (now discontinued).

It is policy to refurbish transformers only if they have life expectancy greater than 15years.

Replacement Criteria

The low cost of new transformers, high cost of operating maintenance facilities and longer life expectancy of new transformers makes replacement the preferred option compared to traditional maintenance.

PLANNED REPLACEMENT PROGRAMME

Transformer Replacement Plan											
		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Small Transformer Age Replacement		50	50	50	50	50	50	50	50	50	50
Growth/Premature Failure Allowance		30	30	30	30	30	30	30	30	30	30
Total Small Transformer Replacements		80	80	80	80	80	80	80	80	80	80
Cost	At 2600ea	392500	208000	208000	208000	208000	208000	208000	208000	208000	208000
Large Transformer Age Replacement		9	9	9	9	9	9	4	4	4	4
Growth/Premature Failure Allowance		4	4	4	4	4	4	4	4	4	4
Total Large Transformers		13	13	13	13	13	13	13	13	13	13
Cost	At 35000ea	535000	455000	455000	455000	455000	455000	455000	455000	455000	455000
Earth Upgrades		4000	4000	4000	4000	4000	4000	4000	4000	4000	4000

GROWTH

Constraints

Large distribution transformers are installed with a minimum 20% excess capacity. This excess provision is permitted to erode with growth until 100% rating is reached. Depending on the load density the transformer is either upgraded or an intermediate transformer is installed.

MDI's are fitted to transformers >100kVA to monitor loadings.

Small transformers are matched as closely to the load as possible and upgraded as required.

Forecasts

ENL monitors loadings on transformers as per 8.B.9 Issues relating to overload transformers are identified and corrected within 12 months. Transformer average growth is in the order of 1MW p.a. Allowance for this is catered for in the Transformer replacement programme above.

Summary of Actions

Allowances for additional transformers and capacity upgrades per year to cater for typical growth are as follows. Negative growth or shifting of load centres creates redundancy of transformer installations.

Large Transformers	3
Small Transformers	20

RELIABILITY AND SERVICE

Standard

All transformer installations are designed to allow restoration within 8 hours.

In most cases portable generation is temporarily used to supply load during replacement of larger transformers.

The security standards adopted by ENL do not allow for temporary supply of loads as a result of smaller transformer failure.

Justification

The standard reflects impact on outage performance statistics.

Criticality

Large unsupported transformers supplying many customers or essential services are given a higher criticality factor when applied risk assessment and replacement programs.

Gap Analysis

Failure analysis shows that the predominant cause of in service failure is tank life being reduced by rust. Re-tanking or repainting is not economic as a standalone action. Failure rates are decreasing due to the implementation of the replacement programme.

Lead failures are related to age. The use of thicker PVC covered leads and elimination of old transformers with downwards facing HT bushing will overcome this problem.

All these failures are in line with normal probabilities over the life of a transformer population.

The following table lists expected quantities of replacements and causes based on current reliability statistics.

Failure or Return Reason	Expected Proportion of Total	Counted As
Rust	59%	Age replacement
Leaks	5%	Age replacement
Lightening	13%	Fault
Animal interference	10%	Fault
Lead failure	10%	Age replacement
Overload	3%	Growth

COMPLIANCE ISSUES

Risk of Failure

The 2000/2001 Compliance Management Plan completed replacement of all known GPC fitted transformers.

The transformer installations that currently pose the highest risk are 100KVA 2 pole platform installations. The main risks associated with these installations are the deterioration of the structures with age and vulnerability to earthquake damage or vehicle collisions.

Earthing and security of installations is considered critical. Compliance with regulations and industry standards must be maintained.

Monitoring
Regular visual Inspection is carried out as per details in 8.B.9

Earth testing is carried out at frequencies detailed in 8.B.9.

Voltage checks are undertaken at customer request.

Issues with structure integrity are identified during Pole inspection programs.

Standard

Earth resistances and equal potential bonding standards are in accordance with the electricity act and regulations.

To upgrade earths a maximum of 6 rods (2 banks) are driven before an earth is abandoned as impractical to lower resistance.

Strength requirements for pole mounted substations are in accordance with the outcomes of the Visim design tool.

Gap Analysis

150 earths with resistance > 100 ohms.

Required Outcome

10% improvement renewal of earths every 6 years as a result of compliance upgrades.

Summary of Actions

The targets necessary to maintain earths that are above the required levels and carry out tests to ensure compliance with standards are as follows:

Earth upgrade programs target elimination of the worst 10% every 6 year testing cycle. In the current cycle this will eliminate all earths with a test > 100 ohms within 3 years.

QUALITY AND DEVELOPMENT

Standardisation

Replacement of transformers with ground mount mini sub style units is the standard practice for transformers over 100kVA Smaller ground mount transformers are also used for replacements in rural locations where the supply is via underground 11kV cables.

- Standard transformer sizes used are 5, 10, 15 kVA for 1 phase supplies 30, 50,100, 200, 300, 500, 750,1000 kVA for 3 phase.
- All transformers above 100kVA to be ground mounted.
- All new urban substations to be ground mounted regardless of size.
- LV isolation to be provided.
- All Urban LV connections to be cable.

- Transformers greater than 500kVA shall have 3-Phase switching provided for connection and disconnection, on the HV

New Technology

Long life tank designs have been adopted as a standard.

Amenity improvements

Removal of 2 pole substations is a major visual improvement.

PERFORMANCE ISSUES

Component Failures

Refurbishment of voltage regulators has proven effective at extending life. A spare unit for contingency is being prepared in 2004.

Ground-mount multi-fin transformers have been identified through inspections, to have rust issues and are developing leaks around the fins. These units also contain Low voltage racks that have also been identified for replacement as per 8.B.12.

NON-ASSET SOLUTIONS

Use of 3 phase transformers in uneconomic areas to allow lower cost 3 phase 400 private service cables to supply small single phase installations has shifted costs from customers to the network in the past. Replacement of 3 phase transformers with 1 phase transformers can be achieved at a 30% lower cost.

Development of pricing structures to encourage more economic construction and reconstruction options for uneconomic regions is intended in the medium term.

8.A.10 Pole Mounted Isolation Equipment

DESCRIPTION

50kV air break isolators are used to provide isolation, bypass, sectionalising and tie functions. In general these switches have integral earth switches, which are used to provide a safe and reliable mechanism for earthing equipment or lines to be worked on. Some switches are motorised.

11kv air break switches are used for isolation and sectionalisation of the overhead distribution network to minimise outage areas and provide practical points of isolation to allow maintenance and fault repairs. The quantities and location of the switches is dependant on distance factors and number of connections between sections. Switch locations in urban areas are generally at feeder inter-tie points and line branches.

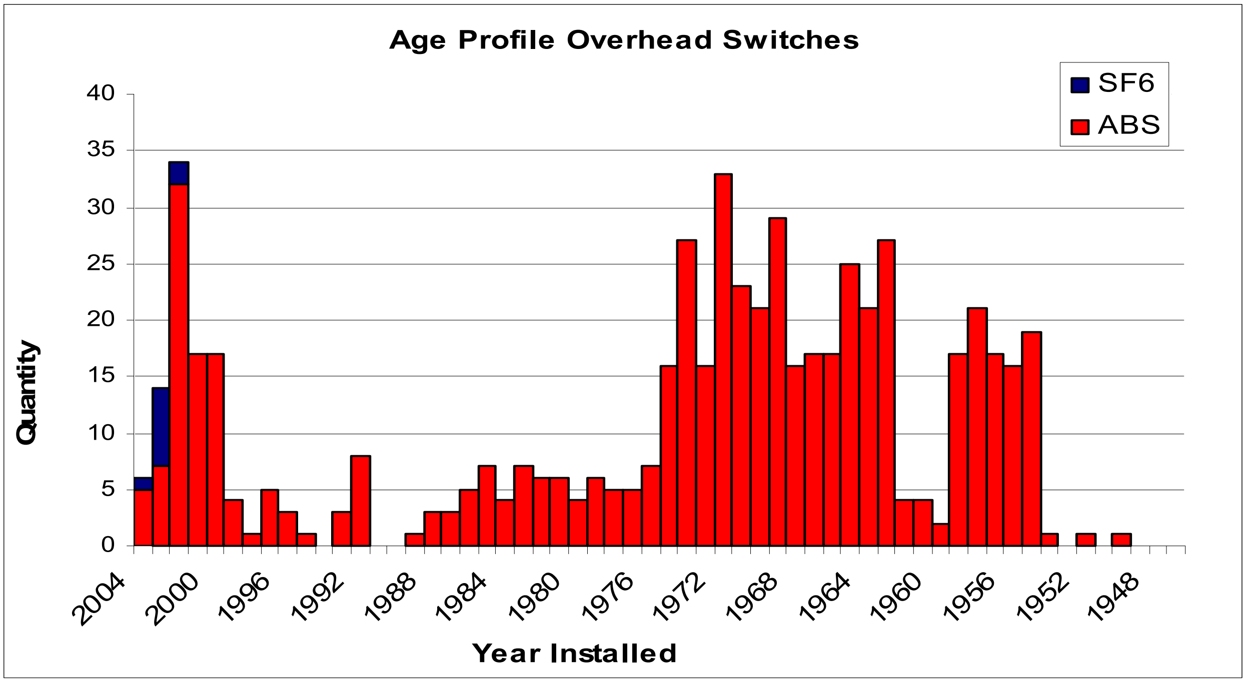
Drop out and glass type 11 kV fuses form the lowest level of protection and isolation functions on the network. All 11kV transformers below 200kVA are protected using 11kV fuses. Rural transformer installations that are connected via a HV service line to the distribution system often have the fuses installed at the tee off from the main line. Branch fusing protects some distribution spurs.

For small 50/11kV 33/11kV transformers with capacity below 1MW Fuses are used for transformer protection.

Switches are used in conjunction with fuses on long sections of cable to provide 3 phase switching reducing the affects of ferro-resonance when the load is small.

LIFE ASSESSMENT (ABS)

ODV Standard Life	35 years
Population size	799
Start of failure period	38 years
Failure period	10 years
Average Residual Quantity	2
Average installation quantity	22/yr
Targeted replacement rate	20/yr
Rate of growth additions	2/yr



Age Profile Comments

Age profile reflects experience. Assets installed during construction with minimal attention/use since. Past service life is leading to high probability of failure if operated.

Density is being reduced therefore all replacements are assumed to be in service failure related.

The high installation period is within the survival roll-off.

It is proposed to replace 20 units p.a. starting in 2002 until 2008 $115,500 p.a. A live line customised network requires clean structures free from any unnecessary equipment, i.e. a minimised configuration.

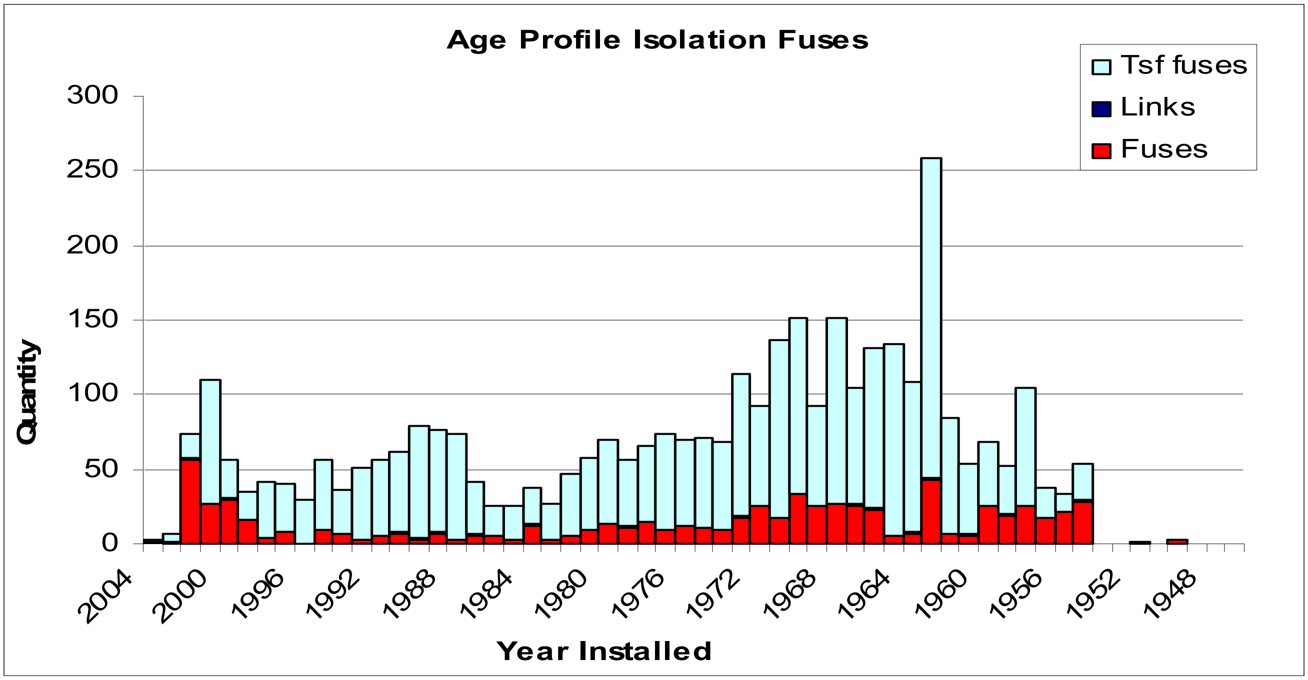
The effects of failure at ABS's are to be minimised through live line design. Design will allow ABS's to be installed, removed, and maintained and by-passed without interruption to supply.

The total average installed age for 50kV switch types is 16 years. There are 78 switches on ENL's network. 5 are motorised.

50kV ABS's have been well maintained and are relatively new. Therefore they are expected to deliver a service life equivalent to the ODV life of 35 years despite criticality. This would require a replacement program starting in 2019 at a rate of 2p.a. Motorised switches (which are used more frequently) would be first priority.

LIFE ASSESSMENT (Fuses)

ODV Standard Life	35years
Population size	2959
Start of failure period	42years
Failure period	7yrs
Average Residual Quantity	2
Average installation quantity	84/yr
Targeted replacement rate	10/yr
Rate of growth additions less reduction	10/yr



Age Profile Comments

- Into replacement cycle as evident in increasing existing installation rates.
- Sudden failure indicates practice of leaving to fail in-service.

PLANNED REPLACEMENT PROGRAMME

The elimination of branch and group fusing would mean that only individual transformers are affected by reliability. This combined with the fact that fuse element faults do not require reporting in outage statistics means that fuses are non critical to performance and can be left to fail in service. It is therefore proposed to flatten the replacement program. It is also proposed to defuse as appropriate. Over the long term, (20 years) the density of fusing will be reduced by 60%. Fuse removal is to be coordinated with the Rural Protection and Automation Project.

Replacement Criteria

- Jammed or rusty bearing surfaces

- Burnt or broken contacts
- Fails to meet standards for rating or live line design

Summary of Actions

ABS's
Replace 20/yr until 2008 $115,000 p.a.
Target steady state of 9/yr. $52,500 p.a.
Target key locations and allow for increased quality and automation.

Fuses
Allow for 10 steady state replacements/new fuse sets per year $12,000 p.a.
Overall population reduction of 4 sets per year
Balance of fuse replacement allowed for in Transformer replacement programme.

GROWTH

Constraints and Triggers

Nil

Forecasts

Growth in the rural distribution system is unlikely to exceed the 1000kVA capacity trigger requiring an ABS to be fitted with arc suppression other than at feeder tie points. These are readily identifiable and dealt with as necessary on an unplanned basis.

However the 50kV ABS's with their close proximity to large conversion transformers require an assessment in terms of operating practice and the need for suppression.

Summary of Actions

Identify arc suppression requirement of 50kV ABS's.

RELIABILITY AND SERVICE

Justification

Any equipment on the network adds to the potential for faulting and requires maintenance. Good design minimises equipment and reduces the risks it poses to reliability.

Criticality

Switchgear used for the purpose of sectionalisation is not considered critical by comparison with similar items used to protect critical equipment from excessive damage under fault conditions; hence the contingency approach for sectionalisation equipment is to bypass the failed equipment.

Actuator units on both 50kV and 11kV ABS's are troublesome planning is underway to determine a solution to the expected unreliability in the medium term.

Gap Analysis

All faults are addressed by minimising asset. Component failure and lack of maintenance do not appear to be issues with ENL's ABS and fuse populations, possibly due to a low level of usage resulting from over population in the past.

Summary of Actions

Nil planned.

COMPLIANCE ISSUES

Quadrant ABS's have been identified by the Electrical Safety Service as a compliance concern.

The proportion of 200Amp Quadrant wire operated Air break switches installed on the network is 70%. These are targeted for elimination between 2004 and 2008. This will be achieved by reducing the installed population as planned replacements, removal, upgrades and the shift to live line working practices is introduced.

Earth testing refer Transformer section.

Standard

Compliance issues are essentially age/location driven. These assets must be upgraded to modern standards within 5 years of reaching their standard life. Until the switches can be eliminated they will be managed with procedures and identification or disabled.

Gap Analysis

The 200A Quadrant ABS's are inadequate for the following reasons: -

- Phase separation is too close. ENL's standard for phase separation is 900mm in order to reduce risk of arc over.
- Open contact spacing is too close to comply with minimum standards for air isolation. The requirement is a gap of 150mm minimum.
- The switches are not rated to break load (10A maximum). Controllers and operators risk making errors in identifying this limitation as it is not identified on site or on the system diagram.
- They are wire operated. The wire passes through live conductors without adequate clearance.
- The handle mechanism is not optimum for clean, swift, positive action.
- Earthing and isolation is not adequate. Earthing of the ABS frame should not rely on the operating wires as conductors.

- The Ministry of Economic Development has indicated that they are past their service life.

Required Outcome

- Removal of all 200A Quadrant ABSs as soon as practicable.

Summary of Actions

As per planned replacement program

QUALITY AND DEVELOPMENT
Standardisation

Standards for Air Break Switches include:

- installations that accommodate live line replacement and maintenance techniques
- 900mm Phase separation on 11kV
- 1400mm phase separation on 50kV
- arc suppression fitted if connected capacity >1MVA on 11kV
- 50kV not used to break load unless fitted with suppression
- load break fault make rating on all new purchases

No transformers greater than 500kVA are installed using fusing protection in overhead areas.

Where sectionalisers or similar equipment are not present on rural lines air break switches are considered necessary at distances not exceeding 10km with typical connection densities of 20 to 30 per section.

New Technology and Innovations

Defusing the HV side of transformers could reduce the faults caused by lightening blowing HV fuses. Optimising location of protection and fault isolating devices will reduce the area of outages. Main causes of outages that can be eliminated by reclosers are transient faults caused by trees, animals and lightening

PERFORMANCE ISSUES

Component Failures

Several types of equipment have been identified throughout the industry as poor performers. This equipment is eliminated through specification.

8.A.11 11kV Switchgear (Ground mounted)

DESCRIPTION

Oil ring main units are typically used in underground networks to provide switching and isolation functions on each section of cable between transformers. The majority of equipment used consists of ABB SD type Ringmain units with extended Isolators or fuse switches where necessary. A few older Reyrolle JK and JS type switchgear, Magnefix and RTE switches are still in service. At newer switchgear installations ABB SF6 indoor / Outdoor and Hawker-Sydley SF6 outdoor units are being used. Ground mounted switchgear is not used where ground mount transformers are located in overhead areas and overhead fusing at the cable tap off is available.

Cast resin or Magnefix switchgear has been used historically as an alternative to the oil filled ring main units. A majority of this equipment was replaced between 2000 and 2003. The remainder of the units are installed in the Wairoa district. In general these units are incorporated into the high voltage cubicle of ground-mounted transformers.

RTE Switches are units that are incorporated into the tank of a ground mounted distribution transformer. They consist of a selector switch that has four positions and have a similar electrical configuration to the oil ring main units. All switching involves a break before make operation of the switch contacts, which causes momentary interruptions to supply. There are limitations on the size of load that the switches can interrupt and generally the switches are operated off load. Only a few RTE units remain in service.

The Reyrolle J type oil switchgear was installed during the 1970's and is located in key areas of the business district. A majority of this equipment was replaced between 2000 and 2003.

Switchgear

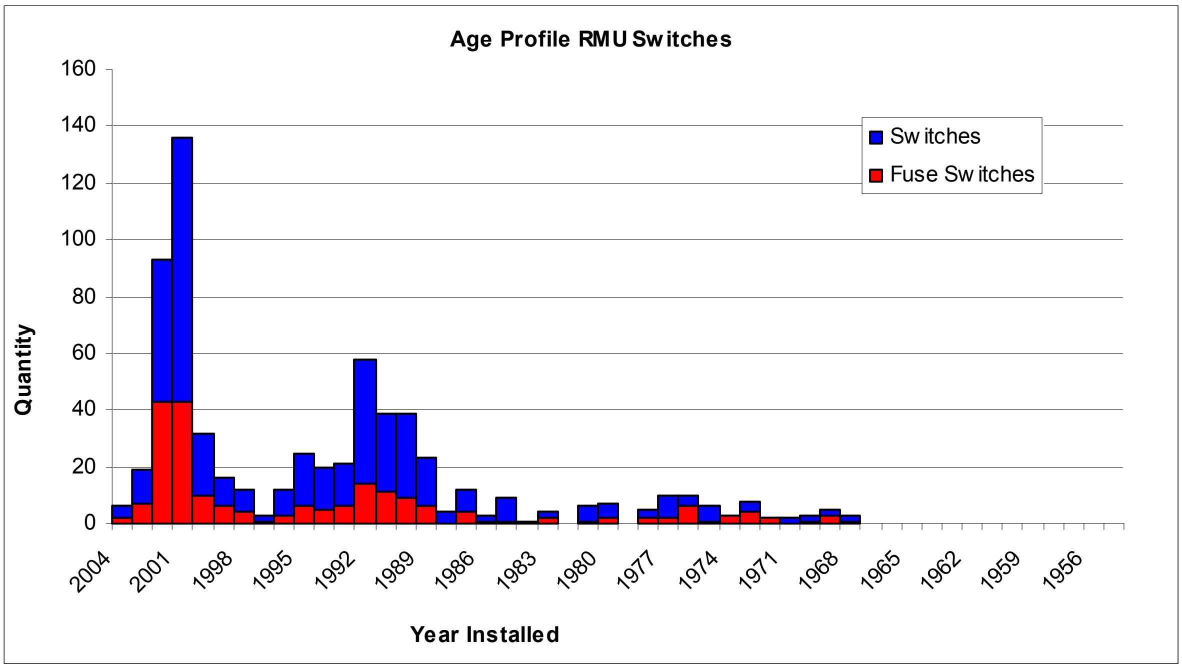
Type	Units	Switches	Avg Age from 2000
RMS Reyrolle	13	39	25 years
RMS (SD)	313	369	11 years
Magnefix	9	27	29 years
RTE	14	42	20 years
Other	148	148	14 years

The switchgear assets are managed on the basis of serial numbered units not on system operational switches

The total average installed age of the assets is 14 years

LIFE ASSESSMENT

Standard ODV Life	40 years
Population Size	657
Start of Failure Period	1989
Failure Period	20 years
Average Residual Quantity	4
Average Installation Quantity	16/yr
Targeted Replacement Rate	15/yr
Rate of Growth Additions	15/yr



Age Profile Comments

Quantities are based on individual switching units as opposed to complete asset containing multiple switching units.

Design deficiencies in older units have largely been eliminated by upgrades.

ENL's population is relatively young.

Quantities installed are dependent on other work such as under grounding reticulation or installing new large transformers.

Replacement Criteria

Replacement of the switchgear is scheduled based on factors including remaining life, repair / replacement economics, and the accessibility of the equipment to be removed from service.

PLANNED REPLACEMENT PROGRAMME

The following list details the priority replacements. The costs include associated cabling and alterations.

Year	Note	Location	Description	Cost
2004/05		B554	Lytton Rd/Findlay/Hospital	$63,000
2004/05	tx	B358	T&G Grey St (Back to Back)	$18,500
2004/05		W264	Wairoa (Hazimayer)	$26,500
2005/06	tx	B417	Masonic Lowe St (Hazimayer)	$45,000
2005/06	tx	B531	Rainbow Grey St(Back to Back)	$16,500
2005/06		W267	Wairoa (Hazimayer)	$31,500
2005/06		W275	Wairoa (Hazimayer)	$26,500
2006/07	tx	B347	Abbott St (Rotary)	$11,500
2006/07		B359	Salvation Arm (rotary)	$26,500
2006/07	tx	B147	Abbott St (Rotary)	$11,500
2006/07		B515	Totara St (Rotary)	$26,500
2006/07		B250	Wildash (Rotary)	$26,500

Note tx : Total cost is less ($35,000 allowance in Transformer Section)

Steady state annual replacements of 5/yr at $36,000 are expected to commence from 2015.

GROWTH

Constraints and Triggers

Growth associated with this switchgear is triggered by industrial load or underground subdivision development. There are no constraints associated with the switchgear as the equipment is rated appropriately to the feeder capacities.

Forecasts

General subdivision development is underway, allowance for 3 units or 9 switches per year is sufficient.

Industrial growth is higher and allowance for 2 units or 6 switches per year is predicted.

Summary of Actions

15 switches per year at $5,400 each=$81,000

RELIABILITY AND SERVICE

Standard

Ground mount switch installations are installed in urban locations where there is no overhead 11kV. As repair is difficult high standards of reliability are required. This equipment needs replacement before in-service failure is risked.

The ring main units, isolators and fuse switches installed generally have a good history of reliability where routine maintenance has been carried out.

No more than 3 transformers supplied from 1 switchboard without bus section

Not more than 500kVA fed from switchgear supplied from a single cable circuit (excluding industrial situations)

No more than 2 transformers and associated switchgear cascaded with no back feed

Not more than 1 cable circuit connected directly to the bus of a switchboard arrangement.

Exceptions to this Standard

Kaiti Sub - Herschell Rd feeder. Slow subdivision development has prevented completion of the 11kV interconnection to the adjacent feeder.

Potae Ave subdivision is due completion by 2006 at which time 11kV interconnection will be achieved.

Justification

Cabled networks are not repaired quickly and do not have alternative temporary by-pass options. They also tend to supply commercial areas. The expense of ground mounted HV switchgear means that its installation is minimised, therefore the loss of a single unit severely restricts operational flexibility.

Criticality

Criticality is high, demanding high levels of equipment integrity and reliability.

Where switchgear is used at critical sites or the consequences of failure threaten safety of personal or property replacement prior to failure is necessary.

Gap Analysis

RTE and Magnefix Switchgear do not meet required reliabily and service levels.

Summary of Actions

Elimination of RTE's in ring configurations and Magnefix equipment is continuing. Refer the planned replacement program above.

COMPLIANCE ISSUES

Monitoring

Annual visual inspections are carried out on all units in service.
Oil sampling and testing is carried out in accordance with maintenance plan.

Standard

Switchgear with a low insulation test or that pose a risk to operators during switching or the public is to be replaced within 2 years.

Gap Analysis

Nil Identified

Summary of Actions

No specific compliance issues.

QUALITY AND DEVELOPMENT

Standardisation

11kV switchgear standards

- Extendable
- Extra height for termination ground clearance
- Independently mounted from transformer.
- 3 phase operation
- Fault make /load break
- 200A fuse tee off rating min.
- 400A Bus bar rating min.
- 12kA short time fault rating min.

New Technology

SCADA control at all inter feeder tie installations is planned over the long term.

SF6 or Vacuum type equipment is now used for replacement to reduce maintenance.

PERFORMANCE

A review of Magnefix performance and maintenance needs have identified units, which should be replaced with alternative types of switchgear to provide three phase switching capability eliminate unnecessary maintenance requirements. Refer Replacement Programme.

Rotary switches contained within the transformer tanks are not operated on load. Replacement of key units in main feeders is identified in the Replacement Programme.

Component Failures

Failure of the equipment is usually caused by failure of the cable terminations on the equipment. Inspection procedures are in place to provide early detection and correction before failure occurs.

8.A.12 LV Switchgear

DESCRIPTION

Ground-mount transformers have an LV frame installed within their Cubical
Approximately 4 runs are bussed on each distribution LV frame.
LV Link-boxes are used at strategic junctions and LV interconnection points between transformers

Note: LV Distribution Pillars are used to contain the disconnection point for customers refer section 8.A.4

Types of equipment include:

- Rewirable fuses replaced with HRC on opportunistic basis.
- Lucy - early standard
- DIN style gauged 3 phase switch panels – existing standard
- Link Boxes - Aluminium construction (Above Ground)

Analysis in this section is limited to cable connected equipment.
All overhead transformers have LV fusing Installed and LV interconnection on the overhead system relies predominantly on jumpers. Replacement of Overhead Fusing equipment is undertaken at Transformer replacement time or following failure.

LV distribution boxes and associated LV frame pillars are placed at interconnection and isolation points between LV feeders and at transformers. Mini sub transformer installations contain the LV frame within their cubical. Others require an independent distribution box.

Link Boxes and Frames

Type	Quantity
Link Boxes	269
Transformer LV Frame	307

LV Fuse Types

Transformer LV Frames	
Type	**Quantity**
ABB	157
Jean Muller	36
Lucy / Old Fuses	80
Other	34
Total	**307**

Link Boxes Summary	
TYPE	**Quantity**
Not Determined	136
ABB SLK 160	26
ABB SLK 400	8
ABB SLK 630	2
ABB SLKNH 160	1
D.O.L	19
EFFEN BRICK	1
J.M GR00 160	4
J.M. GR2 400	13
JEAN MULLER 00	4
JEAN MULLER 01	5
LUCY LARGE	7
LUCY SMALL	27
MP 240	5
NZI FUSE	1
PDL 760	10
Total	**269**

LIFE ASSESSMENT

ODV Standard Life	40 years
Population Size	576
Start of Failure Period	38
Failure Period	10
AMP Version 5.0	155

Average Residual Quantity	0
Average Installation Quantity	14
Targeted replacement rate	14
Rate of Growth Additions	6

Age Comments

This equipment has a relatively young average age because its installation is associated with cables and ground mounting transformers. Therefore it has to be aged to the point where survival can be accurately assessed. However, performance of early installations is driving replacement. Most of this is undertaken in conjunction with other work such as transformer renewal. All new transformers >100kVA are ground mounted therefore new switchgear will be required.

LV frame replacement is allowed for at the same rate as transformer replacements.

PLANNED REPLACEMENT PROGRAMME
Replacement Criteria

If major repair is required the entire box is upgraded to current standards. Minor maintenance is included with transformer allowance.

Replacement of J Type Lucy LV Boxes 6 boxes per year until 2008 $40,000 p.a.
(refer compliance)
Replacement of Lucy Frames is allowed for in transformer replacements.

GROWTH

Constraints and Triggers

Switchgear is sized to the cabling and transformer capacity. It is upgraded if growth of other assets requires it. Increasing load therefore has a limited effect of requiring a larger fuse.

Forecasts

Allowance is made for 6 frames per year $40,000p.a.
Capacity upgrades assume reuse of existing LV frames.

Summary of Actions

Frame Installation as required with transformers.
Growth contingency allows for 6 new Boxes per year.

RELIABILITY AND SERVICE

Standard

Interconnect where practical. Transformers are to be able to be isolated from LV frames. Substation design allows transformers to be replaced without removing LV frame from service.

Justification

There is no performance driver for LV outages.

Criticality

Low criticality except in CBD and commercial subdivisions.

Gap Analysis

Lack of isolation links between the transformer and LV panels restricts the ability to back feed LV circuits via the bus bars in the event of transformer failure.

Summary of Actions

Opportunistic upgrading to standards.

COMPLIANCE ISSUES

Monitoring

Box integrity – clearance and insulation standards.

Standard

Legal compliance with Electricity Regulations. Any work with box will require entire installation to be upgraded.

Gap Analysis

Older LV panels have exposed live bus bars and terminals in close proximity to work areas. The direct connection to transformer terminals exposes the equipment to high fault levels with slow fault clearing times. This is largely a problem with Lucy type frames. The DIN style inherently overcome this issue.
There are approximately 120 sites where replacement of the LV panels of this nature is necessary. Estimated quantities are 80 panels are in ground mount subs and 30 are in stand alone boxes. The replacement of transformer frames is covered by transformer replacements. This is an example of regulatory standards driving improvement at a faster rate than asset age.

Summary of Actions

Refer Planned Replacement.

QUALITY AND DEVELOPMENT

Standardisation

New LV panel installations are constructed using DIN style equipment which is mounted independently from the transformer. Incomer links are fitted to provide the ability to isolate between the transformer and the LV bus bars. This facilitates easy removal and replacement of failed transformers.

400V tie switches are not normally installed on overhead networks interconnections are made using portable jumper sticks in fault conditions. In underground domestic reticulation boltable tie connections are made available at the open points of the LV runs.

New Technology

DIN standard greatly improves quality and performance.

Amenity Improvements

Inclusion of LV frames within mini sub enclosures reduces visual impact of substation.

PERFORMANCE ISSUES

Component Failures

Nil

8.A.13 Control and Protection

DESCRIPTION

Protection equipment includes CB protection relays, Transformer and tap changer temperature sensors, Surge sensors, explosion vents and Oil level sensors.

Types of protection relays used on the network include electro-mechanical, discrete component and microprocessor based equipment. Older CB protection generally includes overcurrent, earth fault, sensitive earth fault (rural feeders) and auto reclose functions. Newer equipment includes voltage, frequency, directional, distance and CB fail functionality in addition to the basic functions.

Batteries, battery chargers, and battery monitors provide the DC supply systems for CB control and protection functions. 110V DC supplies are primarily required for 50kV CB operation and in a number of substations are used for 11kV CB operation and protection. 24V DC supplies are typically used for SCADA RTU'S emergency lighting, protection and CB control at newer installations. The radio communication systems are typically supplied via 12DC systems

Tap changer controls associated with dual transformer installations tap changer controls are configured in a master follower arrangement. Similar equipment is used at single transformer installations. A range of electromechanical, solid state, and microprocessor based controls are used.

Very large technology gains have been made in the last 10 years. These devices are leading progress towards high technology best practice expected even in small rural networks these days.

LIFE ASSESSMENT

Protection equipment was traditionally expected to last the life of the device it protected. However newer electronic equipment is unlikely to perform with adequate reliability after 10 to 15 years. This equipment is required to co-ordinate across the network and therefore must maintain compatibility with ENL's and Transpower's latest technology. Generally technology upgrade is required before age replacement.

PLANNED REPLACEMENT PROGRAMME

Station	Installed	Tapchanger/AVRControl/ Replacement Date	Cost $
Carnarvon Street	1974/1995	2004/2005	*
Parkinson Street	1986	2004/2005	*
Kaiti	1986	2005/2006	*
Pehiri	1996	2006/2007	*
Ngatapa V_Reg	1962	2007/2008	*
Patutahi	1940	2009/2010	*
Pehiri V_Reg	1965	2007/2008	5,000
Kopuroa V_Reg	1984	2008/2009	5,000
Waihua V_Reg	1972	2008/2009	5,000
Matawai V_Reg	1965	2009/2010	5,000
Waingake V_Reg	1964	2009/2010	5,000
Kanakania V_Reg	1964	2009/2010	5,000
Tatapuri V_Reg	1985	2007/2008	5,000

* Costs included with other project work

Voltage regulators are currently fitted with mercury filled switch mechanisims. Replacement with PLC controls is planned when the existing units show signs of maloperation due to mechanical wear approximate dates are identified above.

Station	Voltages	Chargers Installed	Batteries Installed	Due	Total Cost
Kiwi	24,110	1995	1995	2004	15,000
Patutahi	24,110	1996	1999	2004	15,000
Parkinson St	24,110	2006	1998	2006	15,000
Kaiti	24,110	2006	1998	2006	15,000
Te Araroa	24,110	1998	1999	2008	15,000
Tokomaru	24,110	2000	1997	2010	7,000
Ruatoria	24,110	2001	1999	2010	15,000
Tolaga	24	2001	1999	2010	5,000
Puha	24	2001	2000	2010	5,000
Wairoa	24	2001	2000	2011	5,000
Tahaenui	24	2001	2001	2011	2,000
Blacks Pad	12	2001	2001	2011	2,000
Valley Rd Inj	24	2001	2001	na	-
Makaraka	24,110	2000	1999	2011	15,000
Carnarvon St	24,12, ,110	2002/2003	2001	2011	15,000
Port	24	2003	2003	2012	5,000
Pehiri	24,110	1996	2001	2012	5,000
Ngatapa	24,	2000	1999	2007	In project

Rural Automation sites operate either 12 or 24V DC battery systems the average Annual cost to maintain Batteries and Charges at these sites is $3000 p.a.

Station	Feeder Protection Replacement Year	Transformer Protection Replacement Year	50KV Protection Replacement Year
Kiwi	2013	2013	2013
Carnarvon St	2007	2004 *	2004 *
Parkinson St	2008	2004 *	2004 *
Kaiti	2009	2005 *	2005 *
Port	2022	2022	2022
Makaraka	2021	2021	2021
Tokomaru	2020	2018	2018
Tolaga	2021	2020	2020
Puha	2021	2021	2021
Pehiri	N/A	N/A	N/A
Ngatapa	N/A	N/A	N/A
Patutahi	2020	2009 **	2009 **
Te Araroa	2020	1998	2021
Ruatoria	2021	2021	2019
Matawhero	2020	2020	2020
Wairoa	N/A	2020	N/A

*To enable protection coordination following completion of the Matawhero/Parkinson and City 50kV Rings the Protection and controls associated with the 50kV and 11kV Incommers for the transformers at the older sites will need to be upgraded to provide protection necessary to operate the rings closed. Costs for this work are included in the project costs.
**Transformer and 50kV Protection upgrades at Patutahi are coordinated with replacement of the transformer at this site. Costs are included in the transformer replacement costs.

RELIABILITY AND SERVICE

Standard

Protection and control equipment must be stable, accurate and highly reliable.

Justification

Failure of equipment to function or grade with other equipment cause large outages difficult to sort out and may damage critical equipment.

Criticality

Extreme.

Gap Analysis

The quality and performance of ENL's older protection devices does not match its importance to system reliability. The highest levels of technology are required and therefore a 15-year replacement cycle is programmed.

Summary of Actions

Tap change control relays provided by IMP with earlier transformer purchases have proved unreliable requiring 2 or 3 recalibrations or component replacements per year. Failure of the controls causes deviation from required voltage delivery parameters and in rare cases tripping of the transformers.

Steady state allowance of replacement of components following premature failure is assumed at $10,000p.a.

QUALITY AND DEVELOPMENT

Standardisation

New purchases of protection relays include standardisation in terms of flexibility in protection scheme design, communication using standard serial I/O protocols and interchangeable hardware.

It is desirable to keep protection equipment and design consistent across the entire network. Therefore replacement programs are concentrated into a 5-year timeframe.

Standards

For Transformers up to 5MVA Over current /Earth Fault protection is sufficient.
Transformers over 5MVA are to have Restricted Earth fault and Differential Protection.
Tap changer controls shall be capable of Master/ Follower or circulating current operation to cope with unbalanced conditions.
Typically 110V battery is single unit.
Dual 24V Battery systems are to be used where installed CB's operate on 24V and no 110V systems are installed. 24/12-volt DC-DC converters used for Radio equipment power supply.
Battery chargers and batteries including rationalisation of various supply voltages to a common voltage (i.e. 12 volt, 48 volt supplies standardised at 24volts)
Battery Monitors accessed via Telephone line for 110V batteries are installed to ensure close monitoring of the critical supplies for CB tripping circuits.

New Technology
Remote manual controls have been installed on tap changer controls at Zone Substations and on Voltage Regulators as AVR equipment is replaced, to allow operator intervention

when automatic control relays malfunction or when voltage adjustments are necessary when paralleling between to zone substations. Tap changers at new installations or where the older mechanical AVR relays require replacement due to mechanical deterioration, tap changer control relays are selected that operate transformers independently and adjust them selves to minimise losses.

PERFORMANCE ISSUES

Multilin 750/760 Protection relays have a history of issues relating to both firmware and circuitry defects. These defects have been corrected as solutions are identified. The solid-state relays at Kaiti, Parkinson street have setting switches that have caused miss-operation. Similar relays are used at Kiwi substation.

The electro mechanical protection relays used at Carnarvon Street substation have been found to drift from setting values. The Earth fault settings are inverse-time and do not coordinate well with down stream protection equipment.

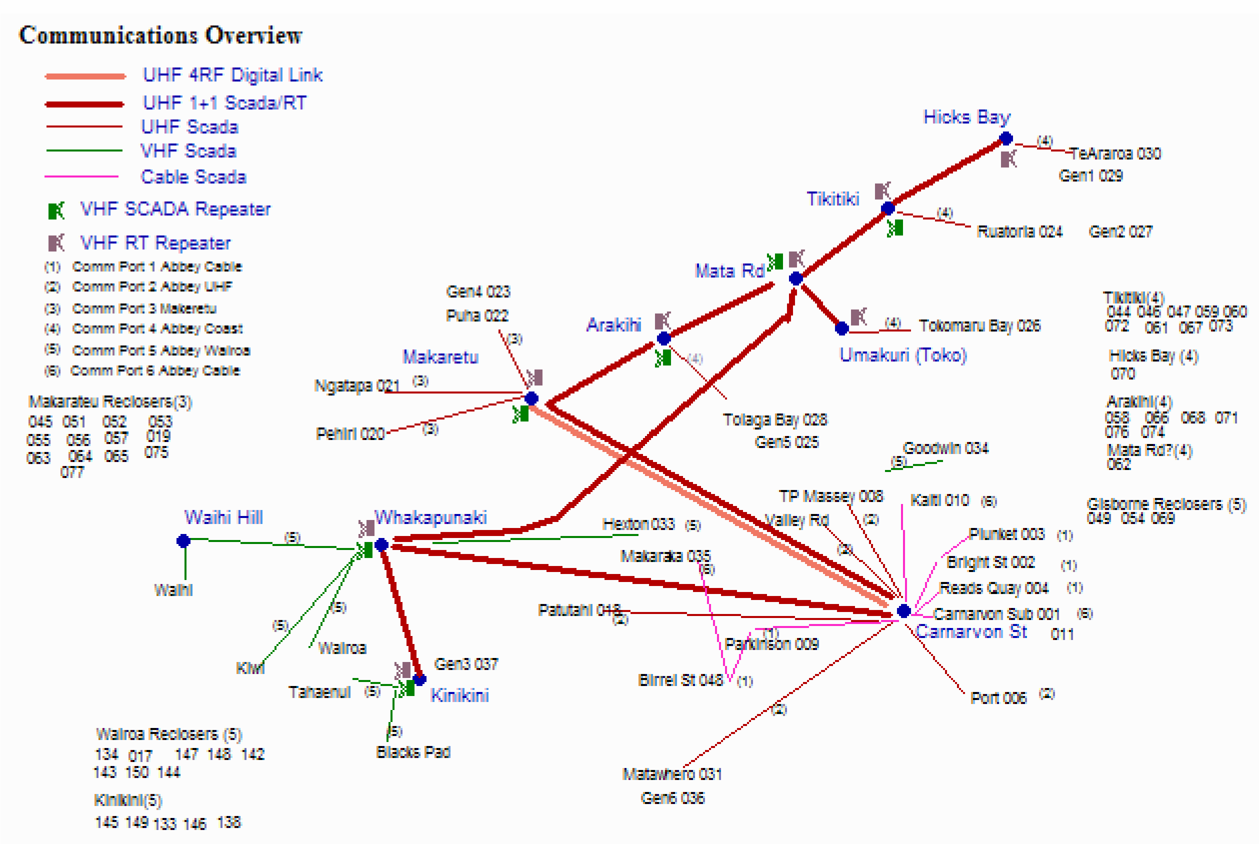
8.A.14 Communications

DESCRIPTION

Nine full duplex UHF communications links are currently used to link the VHF voice repeaters and provide for SCADA communications. These links operate in the 450-465 MHZ FM J-band. Six 1+1 links forming the main back bone of the system between Gisborne and Te Araroa were installed in 1993. A further 2 links were installed in 2000 with new equipment from Gisborne via Whakapunaki to Kinikini. A link is installed between Whakapunaki and Arakihi to facilitate contingent rerouting of communications traffic.

A 4RF Digital Link was installed from Carnarvon St to Makaretu in 2003 to provide additional lines enabling the number of RTU's on a single SCADA port to be reduced improving the poll duration to targeted levels.

Six VHF and seven UHF point to multipoint repeaters are also used for SCADA communications to substations and field recloser sites. This equipment was installed between 1999 and 2001 and consists of a mix of new and reused equipment.



The existing RT or Voice communications system consists of eight VHF FM E-Band 25-watt repeaters. Five of the repeaters are all coupled together via the second channel of the 1+1 UHF links between Gisborne and Te Araroa. One repeater operates from Carnarvon Street primarily for coverage around ENL's offices. The remaining two repeaters are coupled to the

UHF 1+1 system between Gisborne and Kinikini. Both networks are run coupled at the Carnarvon Street control room and have the ability to be decoupled when radio traffic is high. Each repeater can be remotely disconnected from the truck network in the event of a failure.

In order to provide SCADA coverage to the Waihi Power station a short UHF point to point link established in 2002 is used.

A number of communications media and protocols are used to provide voice and data information for operation of the network. Systems include VHF Radio, UHF Radio and Cable. Protocols associated with data communication include Modbus, DNP3, Abbey Systems (HTLC)Sigtec and System DO.

Repeater (Multipoint)	Description	Manufacture/ Install date	Replacement Date	Cost $
Whakapunaki	VHF Voice + Sys DO	1987/1990	2005	12,000
Whakapunaki	VHF Abbey	2000/2000	2008	12,000
Kinikini	VHF Voice + Sys DO	1987/1990	2005	12,000
Kinikini	VHF Abbey	1993/2000	2008	12,000
Carnarvon St	VHF Voice	1990/1990	2005	5,000
Carnarvon St	UHF Abbey	1999/1999	2014	12,000
Umakuri (Tokomaru)	VHF Voice	1993/1993	2008	12,000
Umakuri	UHF Abbey (Tokomaru)	2001/2001	2016	12,000
Tikitiki	UHF Abbey (Ruatoria)	2001/2001	2016	12,000
Tikitiki	VHF Voice	1993/1993	2008	12,000
Tikitiki	VHF Abbey	2002/2002	2017	12,000
Hicks Bay Hill	UHF Abbey (TeAraroa)	2001/2001	2016	12,000
Mata Rd	VHF Voice	1993/1993	2008	12,000
Mata Rd	VHF Abbey	1993/2000	2015	12,000
Makaretu	VHF Abbey	1993/2000	2008	12,000
Makaretu	VHF Voice	1993/1993	2008	12,000
Makaretu	UHF Abbey (Puha)	2001/2001	2016	12,000
Makaretu	UHF Abbey (Ngatapa)	2001/2001	2016	12,000
Arakihi	VHF Voice	1993/1993	2008	12,000
Arakihi	UHF Abbey (Tolaga)	2001/2001	2016	12,000
Arakihi	VHF Abbey	2001/2001	2016	12,000
Waihi Stn on hill	VHF Abbey	2001/2001	2016	12,000

Link (point to point)	Type	Manufacture Date	Replacement Date
Gisborne - Makaretu	UHF 1+1 Data Voice	1993	2008
Gisborne - Makaretu	4RF Digital Link	2003	2018
Makaretu - Arakihi	UHF 1+1 Data Voice	1993	2008
Arakihi – Mata Rd	UHF 1+1 Data Voice	1993	2008
Mata Rd – Umakuri	UHF 1+1 Data Voice	1995	2010
Mata Rd – Tikitiki	UHF 1+1 Data Voice	1993	2008
Tikitiki – Hicks Bay Hill	UHF 1+1 Data Voice	1993	2008
Gisborne - Whakapunaki	UHF 1+1 Data Voice	2000	2015
Whakapunaki – Kini Kini	UHF 1+1 Data Voice	2000	2015
Whakapunaki - Arakihi	UHF 1+1 Data Voice	2001	2016
Waihi Power Station-Waihi Hill	UHF Data	2002	2017

Comms cable (Note Significant circuits only)	Manufacture Date	Replacement Date
Carnarvon St - Gisborne	1987	N/A
Gisborne - Kaiti	1986	N/A
Carnarvon St - Makaraka	1986	N/A
Carnarvon St – Bright St/ Plunket	1986	N/A
Carnarvon St Reads Quay	1986	N/A
Carnarvon St – Parkinson St / Birrel St	1986	N/A

RT's	Quantity	Ave purchase date	Replacement Date
Handheld	10	1994	2009
Vehicle VHF Wide Band	9	1994	2009
Pagers	4	1992	2005
SCADA System DO VHF wide band	23	2002	2017
Substation/Automation sites UHF	15	2001	2016
Substation/Automation sites VHF Narrow Band	51	2002	2017

Generators	Rating	Manuf Date	Replacement Date	Cost
Carnarvon St	12	1960's	2005	$20,000
Makaretu	5	1960's	2006	$10,000
Arakihi	5	1960's	2006	$10,000
Mata Rd	5	1960's	2006	$10,000
Whakapunaki	5	1960's	2006	$10,000
Tikitiki	5	1960's	2006	$10,000

LIFE ASSESSMENT

The standard ODV maximum life assigned to communications equipment is 15 years. Modern equipment with more stable components and self tuning capability generally perform well during this life. Antennas and cables exposed to weather need more regular replacement (10 years). Usually technology advances make earlier system replacement desirable.

PLANNED REPLACEMENT PROGRAMME

A majority of the existing in-service equipment will be due for replacement in 2008 (refer to the table at the beginning of this section).

GROWTH

Constraints and Triggers

Growth is an issue of traffic. As more devices are installed in the field it will become increasingly important to separate data comms from voice channels. Eventually multiple data channels will be desirable.

A maximum of 5 substations and 15 field devices (reclosers, ABS's) or a total of 25 smaller sites are to be hubbed to a single repeater. A chain of no more than 5 links is permitted on any one channel as signal/noise ratios will become unacceptable.

Summary of Actions

A 4RF Digital Link from Gisborne to Whakapunaki to provide additional data channels is planned for 2004/05 as the number of sites on the existing channel will exceed targeted limits. Cost $40,000

The Radio cost to automate an existing switch site is $2000 per site. The Rural Protection and Automation costs in the Circuit breaker section include associated communications costs.

Allowance for 6 additional automated sites per year from 2008 onward is considered sufficient for long term development at a communications cost of $16000 p.a.

RELIABILITY AND SERVICE

Voice comms are critical in terms of being able to operate the network from a central point of control. High reliability is required as ENL's radio network may be the only communication facility during emergency events.

The ability to operate mobile sets in simplex mode provides a degree of contingency.

During periods of high load control the communications to Bulk supply points andLoad control injection plant is vital. Failure may result in excess demand charges. Manual control and monitoring provisions are established at these critical sites

Data communications for remote control of switching devices is less important as equipment can revert to manual operation.

Risks of Failure

The communications network is predominantly radial and any one-link failure results in loss of SCADA communications beyond the failure point. The radial network is satisfactory while reliability is high. Communications to the critical urban substations generally consist of a single radio hop and most have alternative cable circuits.

Whakapunake is a strategic site in terms of its ability to reach neighbouring networks.

Physical cabled communications links to urban substations are vulnerable to damage e.g. car colliding with pole. If the costs to maintain the cable circuits become excessive they are replaced with radio links as they fail.

Description	Estimated Restore Time	Cost Impact	Frequency Factor
Cable circuit Fault	1day (temp radio)	Med	Low
Loss of VHF	1 day	Low	Low
Loss of SCADA link	1 day	Low	Low
Loss of RT in vehicle	1 hr	Low	Low
Loss of access to repeater sites	4 hrs	Med	Low

Description of Contingency Provisions

Telecom connections at the rural substations are utilised as a contingency measure for use in the event of SCADA or R/T communications failure. The connections are also used to monitor systems such as 110 Volt battery banks on a periodic basis and down load meter readings from generator sets at the sites.

Repeaters and 1+1 links can be remotely disconnected via a VHF remote control system (Sigtec) if links fail and jam the network.

Standby generators are provided at significant sites as follows:

- Carnarvon St depot 12kVA
- Makaretu 5kVA
- Arakihi 5kVA
- Mata Rd 5kVA
- Tikitiki 5kVA
- Whakapunaki (ex Wairoa Depot) 5kVA

All repeater sites have power and vehicle access.
Spares are held for all Items of equipment including

- Narrow Band VHF repeater
- Wide Band VHF repeater
- VHF and UHF R/T's
- Complete UHF 1+1 Link
- Minimum Stocks of Aerials and misc items are maintained locally to avoid delivery delays.

A UHF 1+1 Link is installed between Whakapunaki and Mata Rd on hot standby to provide an alternative path for Voice and data Traffic to the remote east coast in the event of failures in the Makaretu Arakihi section of the communications system.

Summary of Actions

Upgrade Carnarvon St standby generator to automate mains fail operation. $5,000 in 2005.

COMPLIANCE ISSUES

Radio interference as it is identified.

Isolation equipment is required to isolate telecom connections and Network communication circuits from earth potential rise in fault conditions at major substations. The isolation facilities are designed to ensure safety of personnel and protection of connected equipment. In areas where cell phone coverage is available telecom connections are being reviewed.

A summary of the isolation facilities at substations are:

Substation	No. of Circuits	Service	Year	Future Costs
Carnarvon Street	9	Voice(4)/Data(5)	2011	$25,000
Valley Rd	3	Telecom/Voice/Data		Nil
Kaiti	2	Telecom / Data		Nil

Parkinson St	2	Telecom / Data		Nil
Makaraka	1	Telecom / Data		Nil
Wairoa	1	Telecom	2005	$5,000
Kiwi	1	Telecom		Nil
Ngatapa	1	Telecom		Nil
Patutahi	1	Telecom		Nil
Pehiri	1	Telecom		Nil
Puha	1	Telecom		Nil
Ruatoria	1	Telecom		Nil
Te Araroa	1	Telecom		Nil
Tokomaru	1	Telecom		Nil
Tolaga	1	Telecom		Nil
Plunket Sub	1	Data	2008	$5,000
Bright St	1	Data	2008	$5,000
Reads Quay	1	Data	2008	$5,000
Birrel St	1	Data	2008	$5,000

Monitoring

To insure the equipment operates within the required limits as per the Regulations. Testing and maintenance is carried out annually on all point to point Radio links and Radio Repeaters.

Cable circuit faults are identified as failures occur.

Standard

- Telecom circuits 10kV isolation on all sites.
- Eastland Network pilot communications circuits 10kV isolation at all sites.
- LTCSS tone calling on all RT's
- Pagers all alpha numeric

Gap Analysis

Currently 5kV isolation levels on data circuits exist at a number of City substations the arrangement of simultaneous access, by personnel working on the circuits to both sides of the isolation panels need to be upgraded.

Required Outcome

For isolation to Telecom – no fault currents developing in a substation may affect Telecom circuits.
For Radio Network – no repeater shall cause interference to jam the entire radio communications network.

- All radio equipment shall be operated within the Communications regulations and licence restrictions

The safety of personnel working on pilot circuits shall be at the highest levels practical for each isolation installation.

No communications from external parties will interrupt RT/Data communications.

Summary of Actions

Improve Isolation facilities at sites identified in the table above.

QUALITY AND DEVELOPMENT

Standardisation

- Equipment at each end of a link to be same make, model and age.
- Power levels standardised on all repeaters at 25W. (Digital links 10W)
- Detachable head RT's to be used in vehicles.

New Technology

With the high rate of charge of communications, technology allowance of $30,000 per year from 2007 on an ongoing basis allowed for new technology.

Development

In general the cable links to substations in the Gisborne urban area are approaching end of economic life and it is intended to replace failing cables with Radio systems or fibre optic circuits. Fibre optic circuits between Kaiti, Port Carnarvon Makaraka Parkinson and Matawhero Zone substations are planned in conjunction with the sub transmission development plan for use with protection circuits. These circuits will also be used to provide SCADA communications and substation telephone lines (reducing Telecom costs).

An increase in digital data equipment used on the radio network to provide for higher speed and increased data volume is expected in the longer term.

PERFORMANCE ISSUES

Component failures

One complete set of spares for a VHF repeater and a UHF link are maintained to ensure minimum down time of the communications network.
Provision of $24,000 p.a. for unplanned equipment replacements following failure is considered sufficient to maintain the communications system.

Makaraka Substation Load Control

Radio communications to Makaraka substation has proven to be un-reliable. The communications to this site are considered critical for operation of the load control injection equipment. Fibre-optic cable installation to replace the failed cable circuit with back up via radio is intended to manage the risks. Programmed for 2004/2005.

8.A.15 SCADA

DESCRIPTION

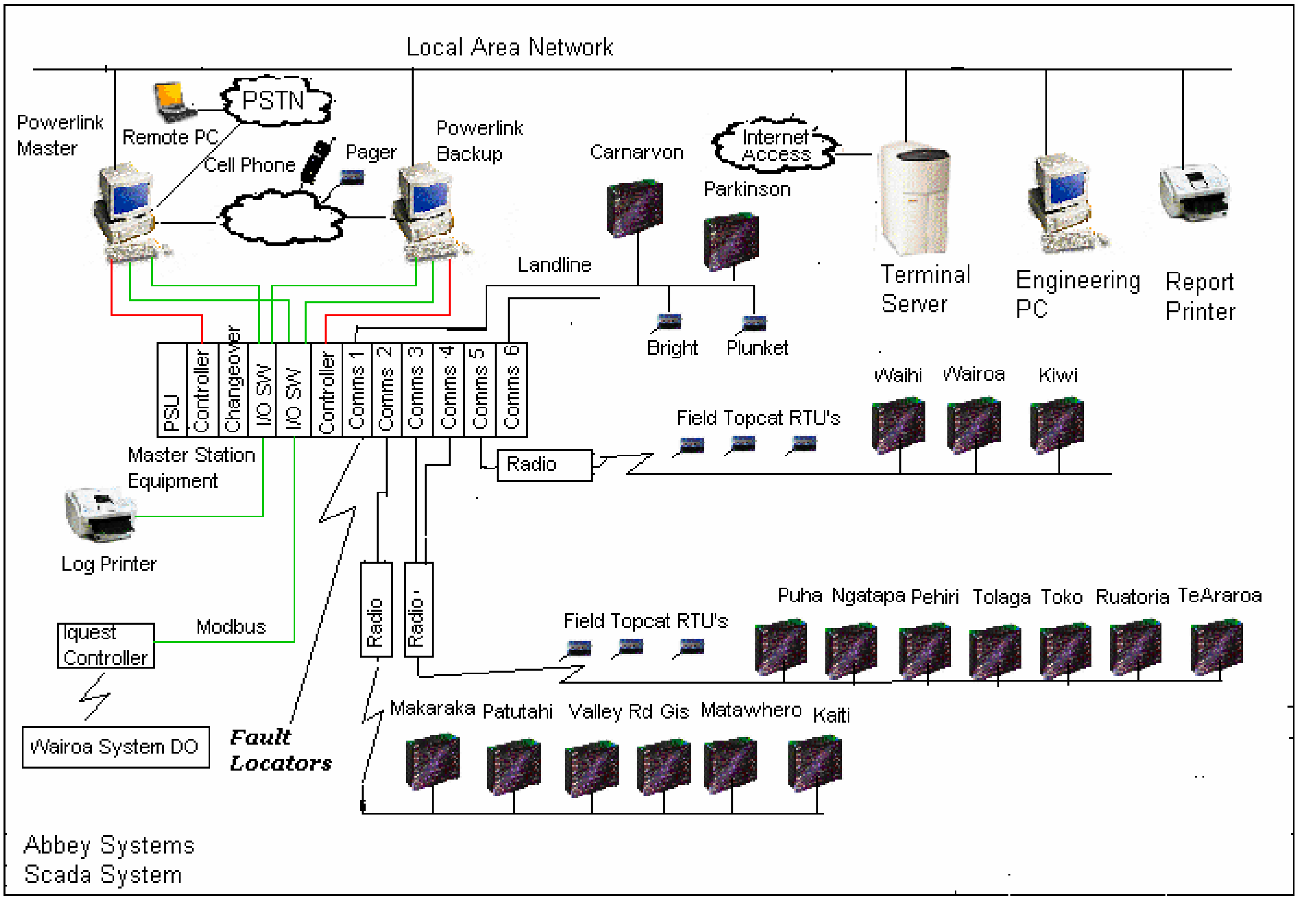
The SCADA master station is located at the head office in Carnarvon Street Gisborne. The system is used for control and monitoring of zone substations and remote switching devices. Point of supply load control functions are also carried out using the system.

An Abbey system Dual Master / Backup master station configuration was installed in 1999.

There are 19 Full RTU installations and 55 remote control switch sites currently installed on the SCADA system.

There are 6 communication ports in use from the Master Station:

Port 1 -	Cable circuit (Gisborne City, 5 Sites)
Port 2 -	UHF Radio repeater (Gisborne City,5 Sites)
Port 3 -	Makarteu circuit (Puha / Matawai Area, 18 Sites)
Port 4 -	Coast radio circuit (Tolaga-Eastcape, 26 Sites)
Port 5 -	Wairoa radio circuit (27 Sites)
Port 6 -	Cable circuit (Gisborne City, 5 Sites)
Serial Port	Modbus for System DO DSCOM9 interface to RT network (Wairoa, 18 Sites)



LIFE ASSESSMENT

SCADA systems have an ODV life of 15 years however as equipment ages beyond 10 years support becomes expensive and replacement technology becomes attractive.

Replacement systems generally cost less, are smarter, less proprietary, etc. Like other computer based systems replacement is frequent and continual.

Replacement Criteria

When technology becomes obsolete.

PLANNED REPLACEMENT PROGRAMME

The original GPT master station and data-term RTU's were replaced between 2000 and 2002 with the current Abbey system. No planned replacements for the Abbey equipment are expected until 2010. At this time a 3 year program to renew the equipment is planned at a cost of $120,000 per year. Unplanned replacement of failed equipment should assume $12000 p.a. between major upgrades.

Replacement of the system DO RTU's commenced in 2001 and will be completed in 2007. The replacements coincide with replacement of the rural automation equipment in the Wairoa district. Scada monitoring and control of repeater sites is currently carried out using a selcom system.

GROWTH

Constraints and Triggers

A requirement of the SCADA system to provide increased compatibility with other systems and devices used on the network is the primary consideration for development and replacement criteria of the assets.

Forecasts

Most major network devices purchased these days come ready for automation. The amount of equipment connected to the SCADA system is expected to double over the next 5 years. A majority of this equipment will be contained at existing RTU sites.
As a result there will be increases in RTU capacity at existing sites and additional small RTU's facilitating automation at strategic points on the distribution network are expected.

Summary of Actions

SCADA control and indication of Transpower feeders at Supply points

With the installation of the Abbey SCADA system at Gisborne substation the ability to communicate directly with the Transpower 50kV circuit breaker control relays for indication and control is possible. This will improve response times and service levels to connections from this substation. Transpower have no objection to the proposal and implementation is programmed to coincide with the 110/50kV Transformer upgrade work.

Remote Control of Switches

The rural protection and automation of sites in the district provides for installation of 30 new sites between 2003 and 2007. In the Wairoa district 23 System DO sites will be replaced with Abbey RTU's between 2003 and 2007.
The purpose of the automation of this equipment is to enable early warning of outages or overload conditions and reduced outage times in remote areas by way of remote control isolation and back feed switching
The RTU cost to automate an existing switch site is $2000 per RTU. The Rural Protection and Automation costs in the Circuit breaker section include associated RTU costs.
Allowance for 6 additional automated sites per year from 2008 onward is considered sufficient for long term development at a cost of $16000 p.a.

Remote Control Waihi Power Station

Automation of the Waihi Power Station was completed in 2001 to allow coordination of the power station load output with the ripple control plant operation at Wairoa. Algorithms to optimise the most economic balance between generation and load control can be handled by the Master Station and the interface with the existing Power Station controller will be via the Abbey RTU equipment, with fine-tuning and improvements carried out on an ongoing basis.

Master Station Development

As the number of sites increases on the network the capacity of the Abbey Master station will be increased. Functionality improvements of the system are also being developed on an ongoing baisis to keep the system current. Ongoing development and replacement on 10 year cycle should assume an average annual cost of $10,000.

RELIABILITY AND SERVICE

Standard

Correct operation of the SCADA system has a direct impact on the service levels and supply restoration response times. As such the reliability requirements of the system are high. The past reliability of the system has been good. Most failures of the system are caused by communications failures. Dual master stations, remote master connection, sub master and island operating capabilities are directly targeted at robustness of the system to faults.
The poll duration of a single SCADA port increases with the number of RTU's connected to the port. When operating remote equipment from the control room maximum poll durations of 35 seconds are targeted to ensure effective operation and feedback from the equipment being controlled. A maximum of 25 RTU's per port is necessary to achieve the targeted poll duration.

Criticality

As for communication equipment and limited by reliability of that equipment.

Risks of failure

Description	Contengency	Custs Min Impact	Cost Impact	Frequency Factor
Operator Stations	Backup available	Low	Low	Low
Comms Stations	Spares available	Low	Low	Low
Back up Supply to Master Station	UPS +Generator	Low	Low	Low
RTU Failure	Spares available	Low	Low	Low
PLC Lock Up	Autoresets installed	Low	Low	Low

Description of Contingency Provisions

In the event of failure of the system appropriate spares are held for the critical equipment items. Manual on site control facilities are also available for all equipment in case of significant communications failures or disaster situations.

Summary of Actions

Consideration is being given to a second master station at an alternate site to provide a duplicate for contingencies in the longer term.

COMPLIANCE ISSUES

N/A

QUALITY AND DEVELOPMENT

Standardisation

- Consistent Protocols
- DNP3
- MODBUS
- ABBEY

New Technology

An upgrade of the SCADA system was implemented in 1999 involving the replacement of the GPT system purchased in 1975. The project was undertaken in order to maintain alignment with newer technology and system flexibility. Increased functionality made available by the new system includes remote configuration and programming of RTU installations, Interfaces to the local area network, portability with the use of cell phone pager, remote computer connections, access via the Internet and compatibility with a wide range of protection and control devices. The system has the potential for inter-connectivity to multiple users and applications to improve on past outage response and restore times.

SCADA systems have the capacity to control much larger networks than ENL's. The Abbey system offers high flexibility in integration and is "fit for purpose" for use in rural network conditions.

Development of a solar powered RT call in system has been developed for use with fault locators. The equipment is designed to activate following a fault to provide indication of the fault location and assist with route planning for dispatch of fault staff to remote locations.

PERFORMANCE ISSUES

Performance issues with the Abbey system are typically a function of communications links and are addressed in the communications section.

8.0B MAINTENANCE

Maintenance is defined in ENL's accounting policies as expenditure required to keep an asset operational until its service life has been reached.

The maintenance section of the life-cycle management plan presents details of the regular on-going work that is necessary to keep assets operating, including the basis for condition monitoring, equipment standards, planned maintenance and provisions for unplanned actions in response to faults or incidents. Condition monitoring activities have been developed for each type of asset. These are presented by individual asset category using the same nomenclature as the capital plans.

Maintenance work is entirely driven from condition and reliability monitoring, as opposed to planned maintenance based on time usage of an asset.

Faults management
All fault response work is contracted to an external service provider. The contract consists of a base management fee and unit rates for labour and plant. Materials are paid for at cost plus set margin. Any Replacement and/or Repair activity required following initial fault response is determined as maintenance or capital in accordance with ENL accounting policies.

Fault management fee:	50kV	$ 9,600
	11kV	$118,500
	400V	$ 19,000
	Load Control	$ 3,800
	Zone Subs	$ 5,900
	Transformers	$ 3,700
	Switches	$ 6,000

8.B.1 50 & 33 kV Lines

A visual ground patrol of every urban 50 and 33 kV pole and the conductors is carried out every twelve (12) months. A helicopter patrol of every rural 50 and 33 kV line is carried out every twelve (12) months. The following points will be included in the inspection:

- Structure foundation erosion (weather or excavator work)
- Structure movement and conductor clearance
- General hardware, insulator and conductor condition
- Early signs of crossarm burning
- Damaged or broken binders
- Monitor vibration dampener performance
- Sabotage

A climbing inspection is carried out on 50 & 33 kV poles every five (5) years.
($150 per pole 330 poles p.a.)

Discharge detection and ultrasound scans of selected areas of Line are undertaken annually. Repairs required as a result of the scans are categorised in terms of risk and scheduled for correction within 1 year.

Pole Assessment Criteria

Every pole has a safety index record which will be updated as a result of ultrasound scan tests.

Poles with a safety index <1.5 are Red tagged and are replaced within 3 months.

Poles with a safety index between 1.5 and 2.5 are identified with a Blue tag and require testing before climbing.

Poles with a safety Index Between 1.5 and 1.75 are replaced within 12 months in high population density or risk areas and within 2 years in other areas.

Poles with a safety Index Between 1.75 and 2.00 have repeat ultrasound scans every 2 years until replaced.

Poles with a safety Index Between 2.00 and 2.50 have repeat ultrasound scans every 5 years until replaced.

Poles with a safety Index Between 2.50 and 3.00 have repeat ultrasound scans every 10 years until replaced.

Poles with a safety Index greater than 3.00 have repeat inspections every 20 years.

Note concrete poles only require a visual inspection per the above as below ground rot does not occur.

Visual inspection identifies at risk poles.

Poles identified as being at risk will have a below ground /Ultrasound scan within 6 months. The results of the test will indicate the need for Red or Blue tagging of the Poles.

Standards

Various standards used include the following:

- AS/NZS 4056, 4676 for Concrete poles
- AS 2209 for Wooden poles
- specific standards for conductors, line hardware and fittings

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Patrols (Ground & Helicopter)	$24,000	2000	$12
Inspections (Climbing)	$50,000	333	$150
Testing – Ultrasound scan (Poles)	$10,000	200	$ 50
Testing (Cables)	$ 0	0	0
Discharge/Ultrasound	$ 14,400	30km	$480

Unplanned Actions

Tree control (refer 11kV Lines and Cables)	N/A
Defect / Fault repairs	$16,200
Fault response (incl Helicopter)	$24,300
Radio Interference correction	$10,000

8.B.2 11kV Lines and Cables

A visual patrol of every pole and the conductors is carried out every ten (10) years. Should any defects be discovered then a full below ground testing will be done within a year.

A tree control program consisting of hazard identification and notification in accordance with the Electricity (Hazards from Trees) Regulations 2003 is being developed. Elements of this programme are:

- Patrolling of the network to identify and record tree interference/ hazards. These patrols are undertaken on 12-18 month cycles.
- The identification of tree owners who's trees are a hazard and the issuing of Hazard Warning Notices or Cut/Trim Notices.
- The engagement of accredited contractors to undertake ENL funded first cuts and/or the removal of "no interest" trees.

Every year the first two (2) kilometres of overhead feeders out of substations are thermo vision and discharge scanned to identify any hot and/or noisy spots.

At risk poles are identified for patrols and testing from the pole database records. Replacement and monitoring strategies are as per the Pole Assessment in 50kV Lines section.

Key 11kV cables have partial discharge monitoring on a five (5) yearly basis. Key cables are established as typically having a length greater than 100 metres and normal load in excess of 40% of the cable rating. Cables requiring replacement are scheduled in the Capital works program.

Storm contingency funding is catered for at $100,000 p.a.

Standards

Various standards used include the following:

- AS/NZS 4056, 4676 for Concrete poles
- AS 2209 for Wooden poles
- Various specific standards for conductors, line hardware, fittings and cable types

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Patrols	$ 30,000	250km	$120
Testing –Ultrasound scan (Poles)	$ 45,000	900	$50
Testing –Partial discharge (Cables)	$ 10,000	20	$500
Tree control program	$150,000	-	-
Storm Contingency	$100,000		
Thermo vision/Ultrasound	$ 10,000	75km	$133

Unplanned Actions	**Total**	**Quantity**	**Unit Cost**
Trees forced cutting	$ 40,500	125	$324
Defect / Fault repairs	$254,320		
Fault response	$120,000	120	$1000
Control and dispatch costs	$ 20,000		

8.B.3 LT Lines and Cables

A visual patrol of every pole and the conductors is carried out every ten (10) years. Should any defects be discovered then a full below ground inspection will be done within a year.

Tree patrols, notification and cutting are undertaken in conjunction with the 11kV Tree Control program.

At risk poles are identified for patrols and testing from the pole database records. Replacement and monitoring strategies are as per the Pole Assessment in 50kV Lines section.

No planned cable maintenance activities are deployed. Replacement is programmed in capital works budget from analysis of performance from fault statistics.

Standards

Various standards used include the following:

- AS/NZS 4056, 4676 for Concrete poles
- AS 2209 for Wooden poles
- Various specific standards for conductors, line hardware and fittings
- Various standards for Cable types used

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Patrols	$15,000	75km	$200
Testing –Ultrasound scan (Poles)	$15,000	300	$50
Testing (Cables)	$ 0		
Tree control Program	Refer 11kV		

Unplanned Actions	**Total**	**Quantity**	**Unit Cost**
Trees forced cutting	Refer 11kV		
Defect / Fault repairs	$ 52,650		
Fault response	$ 28,000	112	$250

8.B.4 Service Connections

Electrical inspectors (not ENL employees) visually patrol and inspect all LV service connections every twenty years. Where the inspection identifies problems liaison is directly with service connection owner. The repairs of the defects are the responsibility of the service connection owner within six (6) months. In cases of high safety risk, and no action by the service connection owner the service connection may be disconnected.

Inspection of Private HV service connections every 5 years is the responsibility of the private owner. However problems identified during 10 yearly visual patrols covered in the 11kV lines section are notified to the private owner for correction within 6 months.

Compliance with Voltage levels is monitored via voltage checks.

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Patrols/inspection	$ 5,000	500	$10

Unplanned Actions	Total	Quantity	Unit Cost
Voltage Checks/Complaints	$32,400	100	$324

8.B.5 Load Control

The Load control injection plant and coupling cells are tested and inspected each year prior to the main winter load period.

Controllable load will be tested each year prior to the main winter load period. Any defects found will be repaired immediately

Standards

Injection equipment is maintained within the Manufacturers specifications for the operating frequency and voltage levels.

Planned Actions	Total	Quantity	Unit Cost
Injection plant testing	$8,000	2	$4000

Unplanned Actions	Total	Quantity	Unit Cost
Defect repairs / replacement costs (Excludes capital relay costs)	$5,000		
Fault response (Pilot circuits)	$10,700	42	$250

8.B.6 Zone Substations

Each Zone Substation will be inspected every three (3) months, this will include inspection and cleaning activities associated with:

- Transformers
- Circuit Breakers
- Switchgear incl. connections or terminations
- Protection and Control Equipment
- Scada and Communications systems
- Structures insulators and bus work
- Overhead line connections
- Voltage regulators
- Zone substation LV switchboards
- DC switchboards and battery systems
- Earthing systems
- Emergency and contingency systems
- Buildings.
- Fences
- Oil containment
- Pest control measures

- Drainage

Safety equipment inspection and testing at each Zone Substation is undertaken 6 monthly.

An independent Occupational Health and Safety inspection of each Zone Substation is made annually.

Thermo vision and Ultrasound inspection of all Zone Substations is carried out annually.

The Earthing system resistance at each Zone Substation is tested every two (2) years

All urgent defects are repaired on discovery, major non urgent defects are repaired within three (3) months, and other minor defects will be included in the normal maintenance programme.

Time based maintenance schedules are maintained for equipment at each Zone substation these schedules are modified following evaluation of inspection and condition assessment results. The typical frequencies range from 2 to 5 years. The lower 2 yearly frequencies are largely due to older equipment. Required equipment maintenance based on inspection and condition monitoring is then carried out. The summary below shows the average annual costs for routine adjustment, testing, calibration and preventative maintenance of the Zone Substation and Rural Voltage Regulator equipment.

Routine Maintenance Summary

Voltage Regulators	$3,000
TeAraroa Sub	$3,000
Ruatoria	$4,000
Tokomaru bay	$4,000
Tolaga Bay	$3,000
Kaiti	$4,000
Carnarvon Street	$4,000
Port	$1,000
Valley Rd	$ 500
Parkinson Street	$4,000
Matawhero	$4,000
Makaraka	$4,000
Patutahi	$4,000
Puha	$3,000
Ngatapa	$3,000
Pehiri	$3,000
Hexton	$ 250
Goodwin Rd	$ 250
Wairoa Substation	$2,000
Kiwi Substation	$4,000
Blacks Pad	$1,000
Tahaenui	$1,000
TOTAL	$60,000

Standards

Environmental standards for noise control and oil contamination levels are maintained within Regional Authority and Local council specifications

Zone Substations are maintained within the requirements of Health and Safety, Electricity, Environmental and Building, Acts, regulations and Codes.

Planned Actions	**Unit**	**Total**
3 Monthly Inspections (25 sites 4 Visits p.a.)	$250	$25,000
Grounds Maintenance (20 sites 12 visits p.a.)	$125	$30,000
Safety Equipment Inspections and testing (20 sites 2 visits p.a.)	$250	$10,000
Occupational Health and safety Inspection (20 sites)	$250	$ 5,000
Thermo vision AND Ultrasound Inspections (20 sites)	$250	$ 5,000
Average Routine Maintenance (refer summary above)		$60,000

Unplanned Actions	**Total**
Defect / Fault repairs	$25,000
Fault response	$ 4,100

Note: work associated with Circuit Breakers, Switching equipment, Control and protection equipment and LV / DC Systems at Zone substations has been included.

8.B.7 Zone Substation Transformers

Activities consist of:

- Bi-annual DGA analysis
- Bi-annual Furans analysis
- Thermo vision as part of substation maintenance
- Painting as required
- Tap changer oil flushing
- Tap changer overhaul per manufacturer's recommendations
- Process oil as required
- Major overhaul as required

Note: Major overhauls are not undertaken on single phase banks. Replacement with a new 3 phase transformer is more economic.

Standards

Based on BS 148 , IEC Standard 42 and Transpower Standards

- Oil acidity < 0.1 mgkOH/g
- Oil electrical strength > 40kV
- Moisture content < 30 ppm
- Resistivity 20 deg >=60 G ohms per metre
- Dissolved gas limits

-Hydrogen	50 ppm
-Methane	50 ppm
-Carbon Monoxide	300 ppm
-Carbon Dioxide	3000 ppm
-Ethylene	100 ppm
-Ethane	100 ppm
-Acetylene	15 ppm

While standards concentrate on maintaining oil condition it is important not to confuse this with transformer condition. These standards must be maintained in order for the transformer to achieve standard life. Exceeding the standards results in permanent damage and shortening of transformer life. DGA analysis provides indication of developing faults and the need for internal maintenance. Trends are monitored to assess expected life/aging.

Specific earthquake restraint designs are provided for the transformer installations.

Planned Actions

DGA furrow tests p.a.	$10,000
Average tap changer overhauls 1 unit p.a.	$15,000
Average oil processing 2 p.a.	$12,000

8.B.8 Circuit Breakers

Substation Circuit breakers are inspected visually during 3 monthly substation inspections. The annual thermo vision survey includes all substation circuit breakers.

Trip testing is carried out in conjunction with protection testing.

Partial discharge testing is carried out on indoor circuit breakers. The frequency of the testing cycle increases as discharge levels increase over time. This work is covered in the zone substations section. This is the main indicator of CB insulation condition and therefore CB life.

Di/dt circuit breaker wear monitoring is implemented where protection equipment has this capability. The information is recorded and assessed as part of the Zone substation inspection work.

The number of trip operations is monitored via SCADA or as part of the 3 monthly / annual inspections.

Remote or field circuit breakers are inspected annually and trip testing is carried out at intervals not exceeding 3 years.

Minor and major maintenance assessments are used to determine end of life and replacement triggers. Work under taken during these activities generally includes:

- Oil replacement
- Adjustment of travel and mechanisms
- Mechanism lubrication
- Contact replacement if required
- Cleaning, painting.
- Trip testing, timing
- Re-insulation, replacement of damaged or worn components.

Variation of discharge or thermo vision results from previous results triggers major maintenance of the circuit breakers

Standards

- AS/NZS 2650 Common specifications for HV switchgear.
- Manufactures specifications for each type of equipment.
- Transpower standards and recommendations for minor and major maintenance frequencies derived from industry experience.
- Oil circuit breakers servicing.
  50kV CB's after 2 fault trips or 2 years
  11kV CB's after 8 fault trips or 3 years

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Annual Inspections (Rural CB's)	$10,000	40	$ 250
Average Routine Maintenance (Rural CB's)	$20,000	8	$2,500

Unplanned Actions	**Total**	**Quantity**	**Unit Cost**
Defect /Fault repairs	$15,000		

Note: work associated with Circuit Breakers at Zone substations is included in the Zone substations section.

8.B.9 Distribution Transformers

Smaller transformers generally in rural locations are inspected in conjunction with earth testing programs and pole surveys. Transformers with an installed age over 35 years are specifically checked every 3 years to identify units with excessive external deterioration of the tanks or 11kV tails where they are internally connected, for replacement.

In all cases the units are checked during earth testing/switchgear inspections at intervals not exceeding 5 years.

Oil testing is carried out on transformers 500kVA and above the frequency of the tests varies depending on the analysis results and but does not exceed 5 years on any single unit over 20 years old.

Ground mount substations undergo an annual visual inspection. Items covered in the inspection include inspection of the LV panels, associated 11kV switchgear, Load readings, high voltage terminations, earthing and warning/security notices.

General maintenance activities as a result of the inspections include painting on site, vegetation clearing, LV panel cleaning and labelling.

Transformer loading on ground mount substations is monitored annually via MDI readings. Low voltage panels of all Ground style substations over 100kVA are inspected annually MDI readings are recorded.

All ground mount units located in areas accessible to the pubic receive a Certificate of compliance check every 5 years.

No maintenance activities are carried out on smaller in-service transformers.

Transformers returned from the field for service, receive minor refurbishment work is carried out where the age of the units is less than 20 years old.

Earth testing is carried out on a 5 year cycle. Earths include distribution substations, switch sites and LV earths. Earthing system repairs are undertaken on the worst 20% of earth tests above 50 ohms. Earth tests between 0 and 50 ohms are considered adequate in terms of the expected seasonal variation in ground moisture content.

Standards

Refurbishment is only considered if the transformer condition is such that it has 15 years remaining service life and cost is less than 25% of a new transformer. Economics is limited by the frequency of relatively expensive recovery and installation.

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Refurbishment <100kVA	$ 7,500	5	$1500
Refurbishment >100kVA	$ 8,000	2	$4000
Painting Ground mount/graffiti	$ 3,000	20	$150
Annual Ground mount Inspection and MDI’s	$10,000	200	$50
Oil Handling /filtering /TX disposal	$10,000		
Transformer 5 yearly Compliance checks	$ 5,000	100	$50
Earth testing	$45,000	1000	$45
Earthing system repairs	$30,000 `	60	$500
Oil Analysis	$ 6,000	20	$300

Unplanned Actions	Total	Quantity	Unit Cost
Defect /Fault repairs	$16,200		
Vegetation clearance	$ 1,000		

8.B.10 Pole Mounted Isolation Equipment

Inspection of all 50KV air break switches is carried out in conjunction with climbing patrols 2 yearly. Visual inspection of the switch contacts and mechanism and Inspection and testing of the earthing (refer earth testing in the Transformer section) is carried out.

ABS's not operated regularly enough to maintain correct function are clearly not necessary and targets for removal.

Testing operation of the switch is carried out where this is possible without a shut down. Live line methods are deployed to carry out maintenance on switches where necessary.

Defects are documented as found and corrective action prioritised as necessary to prevent failure in service. This may involve nil operation until the opportunity to coordinate with other work.

Standards

- Equipment maintained in accordance with Manufacturers specifications.

Planned Actions	Total	Quantity	Unit Cost
Inspection and Testing	$12,000	40	$300
Unplanned Actions			
Defect /Fault repairs	$12,960		

Note: work associated with pole mounted isolation equipment at zone substations is included in the zone substations section

8.B.11 11kV Switchgear (Ground mounted)

Ring main units, oil filled isolators, fuse units and magnefix are inspected yearly. A service / inspection requiring a shutdown is carried out at intervals not exceeding 5 years.

At larger industrial substations switchgear is surveyed bi-annually using thermo-vision equipment. The survey generally provides early warning of poor or failing connections to the switchgear and poor contacts. The frequency of monitoring will be increased if testing identifies problems developing at a higher rate.

Partial Discharge monitoring is also carried out on larger switchboards at intervals not exceeding 5 years where proximity to transformers does not cause interference. The frequency of monitoring will be increased if testing identifies problems developing at a higher rate.

Standards

- Oil leaks and low oil levels are repaired within 6 months.
- Rust is treated within 12 months.

Maintenance Activities

For RTE switches maintenance is carried out in conjunction with refurbishment of the transformers when they are removed from service.

Routine maintenance work requiring shut downs is opportunistic. This is a major constraint on the level of confidence that can be applied to equipment reliability.

Servicing is carried out on the basis of the inspection results. Activities include:
- exterior painting on site
- oil replacement
- contact replacement
- termination inspections and cleaning where possible
- termination replacement

Quadrant type air break switches are targeted for removal as identified in Section 8.A.10. A cost of $40,000p.a for the next 5 years will be expenced to remove these assets.

Planned Actions	Total	Quantity	Unit Cost
Annual Inspection	$ 10,000	167	$60
Average Switch maintenance p.a.	$ 18,000	18	$1,000
5 Yearly Service Inspection	$ 20,000	7	$3,000
Termination Inspection	$ 10,000	80	$ 125
Quadrant ABS Removal	$ 40,000	100p.a.	$ 400

Unplanned Actions	Total	Quantity	Unit Cost
Defect /Fault repairs	$11,400		

8.B.12 LV Switchgear

A visual patrol of LV Disconnection and Link boxes is carried out every 5 years and larger link boxes are checked and cleaned during 3 yearly inspections.

LV panels in ground mount substations are inspected in conjunction with annual transformer Inspections. No routine maintenance activities are undertaken on overhead LV equipment.

Standards

Legal compliance and pre-emption of faults.

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Inspections/servicing	$15,000	50	$300

Unplanned Actions	**Total**	**Quantity**	**Unit Cost**
Defect /Fault repairs	$9,100		
Painting / Graffiti	$ 4,000		

8.B.13 Control and Protection

Operation of the equipment is monitored via the SCADA system all operation events are investigated to ensure the operation of devices occurred correctly. Incorrect operation of protection has been found to occur with some equipment types typically in relation to auto-reclose controls. Relay testing and CB trip testing frequencies for relays vary depending on the type and age of devices. The functionality of the tapchangers is monitored via the SCADA system.

Battery 110V. To ensure close monitoring of battery condition and loading to maximize life of the new batteries proposed, battery monitors will be installed. The monitors will reduce future battery maintenance costs.

Battery handling procedures and facilities are incorporated into health and safety inspections annually.

Standards

- Within manufactures specs for individual relays and equipment.
- Where liquid batteries are contained within buildings separate rooms are used with good ventilation. Where this cannot be achieved batteries are housed in outdoor containers.

Maintenance Activities

Tap change control – Adjustment and calibration of AVR’s not exceeding 4 yearly
Transducers – calibration not exceeding 4 yearly

24V battery systems – First test 2 years after initial installation, thereafter annual Load test on 24V battery systems
110V battery systems – Annual physical inspection and load test (monitoring on line)
Protection Electromechanical – Annual secondary tests
Protection Solid-state – 3 yearly secondary tests
Protection Microprocessor – 4 yearly tests
CB trip testing – Not exceeding 4 yearly (refer Circuit Breaker maintenance)
Transformer protection not exceeding 4 yearly
Fire safety and intruder systems not exceeding 6 monthly

Note: work associated with protection and control equipment is included in the related asset section.

8.B.14 COMMUNICATIONS

A degree of remote monitoring of the radio systems is in place to provide early warning of equipment malfunction. Six monthly testing and calibration is carried out to ensure the equipment performance is within specification.

Standards

- Complies with the Radio Spectrum Management Conditions and Radio Communication Regulations.
- Operates within manufacturers specifications
- Power : repeaters – 25W, RTs – 5W
- Drift : 2 kHZ
- Frequency
- Heat levels within manufacturers specifications
- One complete spare link and 2 portable repeaters are maintained for contingency operations.

Planned Actions	**Total**
Maintenance/Calibration	$35,000
Track Maintenance	$10,000
Hut Maintenance	$ 4,000
Radio Licences	$13,000

Unplanned Actions

Defect/Fault repairs	$16,000

8.B.15 SCADA

In general the RTU Input and output functions are tested in conjunction with maintenance of the associated equipment. During Protection and Switchgear testing the Digital indications, analogues, measurement and control functions are verified back to the master station. General indications such as door security and Fire alarms are verified during 3 monthly inspections.

Other indications such as DC Battery and Mains Fail alarms are verified during RTU inspections at intervals not exceeding 2 years. This work is generally coordinated with other activities being undertaken at the substations.

Standards

- Operates within manufacturers specifications

Planned Actions	**Total**
Support fees	$10,000
Software Licences	$ 5,000
SCADA maintenance allowance	$10,000
Point to point testing of Digital IO	$10,000
Configuration file alterations	$ 6,000

Unplanned Actions

Defect/Fault repairs	$ 10,000

9.0 FINANCIAL SUMMARY

9.1 Financial Projections

Financial projections are one of the key outputs of this AMP, representing the financial outcome of the management strategies and specific maintenance, renewal and development plans set out herein. They outline ENLs network expenditure over the planning period, separating capital and maintenance related expenditure.

Capital expenditure is defined as expenditure that results in increased value of an asset, where the value is defined by service potential (capacity) to derive future benefits, earnings or reduced costs. If extra expenditure, say from an alteration to the original asset, results in extra value after satisfying an independent test on commercial viability, then it is capital expenditure. Overhead to underground conversion, life extension and load driven capacity upgrades fit into this category.

Maintenance expenditure is defined as expenditure required to operate an asset or keep it in the minimum acceptable serviceable condition needed to continue its earning until the asset has satisfied the life and earning expectations used to establish the commercial viability of the original investment decision. Commercial viability tests will assume a certain level of operating and maintenance expense. Expenditure beyond this level may threaten commercial viability. Sensitivity to this and other risks are weighted into investment decisions**.**

9.1.1 Capital Expenditure

The capital expenditure forecast is summarised in Tables 9.1.1A and 9.1.1B by asset type and by expenditure category (or driver) respectively, using the same categorisation presented in Section 8.0A of this AMP. Detail of the expenditure is shown in Table 9.1.1C

Figures 9.1.1D,E,F graphically illustrates the same information over the planning period.

9.1.1A	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	
Summary by Asset Group	**$11,350,006**	**$7,856,970**	**$6,057,790**	**$6,815,200**	**$6,335,000**	**$6,604,700**	**$6,222,950**	**$5,219,500**	**$5,161,500**	**$5,757,500**	**$67,381,116**
Generation Peaking Plants	$440,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$440,000**
50 kV Lines	$4,124,955	$1,890,000	$370,000	$340,000	$340,000	$340,000	$340,000	$340,000	$340,000	$340,000	**$8,764,955**
11kV Lines and Cables	$2,177,600	$3,252,900	$3,306,000	$3,543,200	$3,055,000	$3,410,200	$3,426,450	$3,080,000	$3,080,000	$3,680,000	**$32,011,350**
LT Lines and Cables	$504,000	$640,000	$640,000	$640,000	$640,000	$640,000	$640,000	$640,000	$640,000	$640,000	**$6,264,000**
Service Connections	$70,000	$70,000	$40,000	$40,000	$40,000	$40,000	$40,000	$20,000	$20,000	$20,000	**$400,000**
Load Control	$250,000	$450,000	$250,000	$250,000	$250,000	$450,000	$250,000	$0	$0	$0	**$2,150,000**
Zone Substations	$1,843,231	$0	$0	$700,000	$500,000	$500,000	$250,000	$0	$0	$0	**$3,793,231**
50kV CB's	$50,000	$100,000	$0	$0	$160,000	$160,000	$160,000	$0	$0	$0	**$630,000**
11kV CB's	$326,720	$290,570	$205,290	$148,000	$0	$0	$0	$0	$0	$0	**$970,580**
Distribution Transformers	$971,500	$667,000	$667,000	$667,000	$667,000	$667,000	$667,000	$667,000	$667,000	$667,000	**$6,974,500**
Pole Mounted Isolation Equipment	$127,000	$127,000	$127,000	$127,000	$127,000	$64,500	$64,500	$64,500	$64,500	$64,500	**$957,500**
11kV Ground Mounted Switchgear	$189,000	$200,500	$183,500	$81,000	$81,000	$81,000	$81,000	$81,000	$81,000	$81,000	**$1,140,000**
LV Switchgear	$80,000	$80,000	$80,000	$80,000	$80,000	$40,000	$40,000	$40,000	$40,000	$40,000	**$600,000**
Control and Protection	$70,000	$13,000	$63,000	$105,000	$118,000	$108,000	$33,000	$51,000	$18,000	$118,000	**$697,000**
Communications	$104,000	$54,000	$104,000	$54,000	$239,000	$66,000	$90,000	$95,000	$70,000	$82,000	**$958,000**
SCADA	$22,000	$22,000	$22,000	$40,000	$38,000	$38,000	$141,000	$141,000	$141,000	$25,000	**$630,000**

9.1.1B	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Performance/Development	**6,257,656**	**2,740,570**	**965,290**	**1,058,000**	**276,000**	**476,000**	**266,000**	**16,000**	**16,000**	**20,000**
Growth/Security	**1,506,100**	**1,181,900**	**1,235,000**	**2,022,200**	**1,470,000**	**1,255,200**	**1,271,450**	**925,000**	**925,000**	**925,000**
Condition/Compliance	**3,586,250**	**3,934,500**	**3,857,500**	**3,735,000**	**4,589,000**	**4,873,500**	**4,685,500**	**4,278,500**	**4,220,500**	**4,812,500**

9.1.1C

Capital Expenditure Projections

Description		2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
TOTALS		**11,350,006**	**7,856,970**	**6,057,790**	**6,815,200**	**6,335,000**	**6,604,700**	**6,222,950**	**5,219,500**	**5,161,500**	**5,757,500**
Generation Peaking Plants		**440,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Generators Puha/Patutahi	Development	160000									
Generators Mahia/Frasertown	Development	220000									
Generators Ruatoria/TeAraroa	Development	60000									
50 kV Lines		**4,124,955**	**1,890,000**	**370,000**	**340,000**	**340,000**	**340,000**	**340,000**	**340,000**	**340,000**	**340,000**
Age replacement 90 poles per Year	Condition Compliance	360,000									
Age replacement 40 poles per Year	Condition Compliance		240,000	240,000	240,000	240,000	240,000	240,000	240,000	240,000	240,000
Age replacement 45 poles defered from 2002	Condition Compliance	80,000									
Age replacement Insulators Mahia 33kV	Condition Compliance	34,000									
NZED 2nd hand Insulator replacement	Condition Compliance	39,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Surge arrestor replacement Gisborne 50kV	Condition Compliance	30,000	30,000	30,000							
OB Insulator Replacement	Condition Compliance	29,250	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Close 50kV Ring JNL-Parkinson SFE02/4	Development	1,796,688									
Close 50kV City Ring SFE02/7	Development	1,716,017									
Mahia 33kV line extension and Substation	Development		1,520,000								
Fault Replacement Line	Condition Compliance	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
11kV Lines and Cables		**2,177,600**	**3,252,900**	**3,306,000**	**3,543,200**	**3,055,000**	**3,410,200**	**3,426,450**	**3,080,000**	**3,080,000**	**3,680,000**
Age Replacement 450 poles per year	Condition Compliance	900,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
Conductor replacement 20km	Condition Compliance		600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	
Conductor replacement 40km from 2013	Condition Compliance										1,200,000
Unplanned Network Extention Alowance Line 2km	Growth		180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000

Uneconomic Rural Line replacement 20km	Condition Compliance						600,000	600,000	600,000	600,000	600,000
Unplanned Network Extention Alowance Cable 1km	Growth	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Allowance for Growth and Fault Line	Growth	180,000									
Reconductor Mahia 6km	Growth	135,000									
Construct 6km new line to Waihi-Otoi	Growth	210,000									
Reinforce 6km line to Otoi to ring	Growth	210,000									
Masonic Sub Lowe St to Farmers Sub Customhouse St	Growth	22,400									
Masonic Sub Lowe St to Govt Building Sub Lowe St	Growth	25,200									
Campion Rd-Nelson Rd tie cable 200m	Growth	35,000									
Replace double circuit with lager conductor from Tokomaru to Ruatoria	Condition Compliance	40,000									
Age Replacement Steel Defered from 2003/2004	Condition Compliance	60,000									
Age Replacement Steel Conductor	Condition Compliance	120,000									
Age Replacement 7/16Cu	Condition Compliance	40,000									
Reconductor Tamarua Feeder 1.7km	Growth		51,000								
Reconductor Wairere Rd 1.5km	Growth		45,000								
Reconductor Patutahi 1.2km	Growth		36,000								
Reconductor Bell Rd 1km	Growth		30,000								
Matawhero-Muriwai 11kV Line	Growth			135,000							
Dalton Feeder Moana Rd bypass 1.4km	Growth				98,000						
Ngatapa to Otoko Hill 8km	Growth					250,000					
Reinforce 13km Cricklewood Spur	Growth						200,000	190,000			
Cable Masonic to Bright Street 150m	Growth		28,500								
Cable Farmers Customhouse to Reids Quay 260m	Growth		49,400								
Cable Reids Quay to Weigh bridge 300m	Growth		63,000								
Cable Childers Disraeli Corner 300m	Growth			60,500							
Cable Roebuck Rd Palmerston Corner 300m	Growth			60,500							
Cable Roebuck Rd Bridge 350m	Growth			70,000	56,000						
Cable Carnarvon Sub to Childers Rd 560m	Growth				112,000						
Cable Stanley Rd Bridge 400m	Growth				80,000						
Cable Plunket Sub to Ormond Rd 320m	Growth				67,200						
Cable City Feeder (Paknsave) 525m	Growth					105,000					
Cable Kahutia St feeder 1100m	Growth					220,000					
Cable Reids Quay to IRD 290m	Growth						60,900				
Cable IRD to Plunket Sub 330m	Growth						69,300				

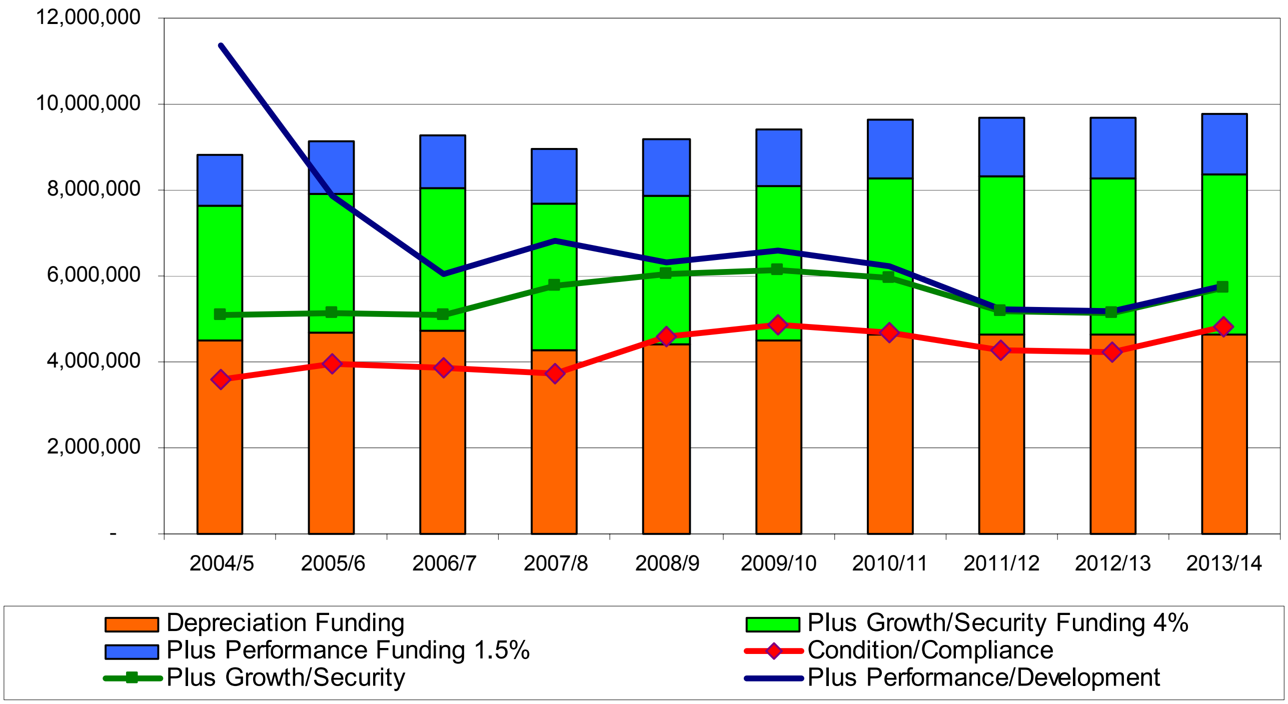
Cable Weigh Bridge to Hirini St 370m	Growth							77,700			
Cable Oak to Stout St 375m	Growth							78,750			
Gladstone Rd Project	Development		470,000	500,000	650,000						
LT Lines and Cables		**504,000**	**640,000**	**640,000**	**640,000**	**640,000**	**640,000**	**640,000**	**640,000**	**640,000**	**640,000**
Line Replacement 2km	Condition Compliance	69,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Pole replacement 50 per year	Condition Compliance	60,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Age replacement Cables 2km	Condition Compliance		160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Allowance for Growth Cables 2km	Growth	110,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Line Replacement with Underground 2km	Condition Compliance	165,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Eliminate Low Road crossings 25pa	Condition Compliance	100,000									
Service Connections		**70,000**	**70,000**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**	**20,000**	**20,000**	**20,000**
New Service Fuse Boxes to Replace Fibreglass Boxes 40pa	Condition Compliance	40,000	40,000	40,000	40,000	40,000	40,000	40,000			
Service Box Replacement 20 p.a.	Condition Compliance								20,000	20,000	20,000
New Service Fuse Boxes to Replace Meter Box Sharing 40 pa	Condition Compliance	30,000	30,000								
Load Control		**250,000**	**450,000**	**250,000**	**250,000**	**250,000**	**450,000**	**250,000**	**0**	**0**	**0**
Replace contactors with ripple relays 1200 pa	Performance	250,000	250,000	250,000	250,000	250,000	250,000	250,000	0	0	0
Relocation Valley Rd Injection Plant to Wairoa	Performance										
Aquire Spares and Install second Injection Point Gisborne	Performance		200,000				200,000				
Zone Substations		**1,843,231**	**0**	**0**	**700,000**	**500,000**	**500,000**	**250,000**	**0**	**0**	**0**
T2 12.5MW Parkinson	Development	536,000									
JNL Zone Substation	Development	$1,082,231									
Overhaul Carnarvon T2	Condition Compliance	30,000									
Supply bypass 11kV Sw Board Wairoa	Development	37,000									
Transpower Tuai Bypass	Performance	63000									
Bunding and Oil Seperator Parkinson St T1	Condition	40,000									

	Compliance										
Earth Quake Brackets Parkinson St T1	Condition Compliance	15,000									
Bunding Carnarvon St T2	Condition Compliance	25,000									
Earth Quake Brackets Carnarvon St T2	Condition Compliance	15,000									
Replace T1 at Tolaga 2.5MW	Condition Compliance					500,000					
Replace T1 Patutahi 5.0MW	Condition Compliance						500,000				
Replace T1 Puha 5.0MW	Condition Compliance							250,000			
T1 2.5MW and new sub Whangara (overcomes capacity issues of Kaiti and Tolaga)	Development										
Replace T1 Ngatapa 2.5MVA	Growth				700,000						
50kV CB's		**50,000**	**100,000**	**0**	**0**	**160,000**	**160,000**	**160,000**	**0**	**0**	**0**
TeAraroa	Condition Compliance					80,000					
Ruatoria T1	Condition Compliance						80,000				
Ruatoria Line to TeAraroa	Condition Compliance						80,000				
Tokomaru T1	Condition Compliance							80,000			
Tokomaru Line to Ruatoria	Condition Compliance							80,000			
Tolaga T1	Condition Compliance					80,000					
Patutahi T1 CB Installation	Condition Compliance	50000									
Patutahi Line CB Replacement	Condition Compliance		50,000								
Pehiri CB replacement	Condition Compliance		50,000								
11kV CB's		**326,720**	**290,570**	**205,290**	**148,000**	**0**	**0**	**0**	**0**	**0**	**0**
Field Recloser Automation Plan	Performance	326,720	290,570	205,290	148,000						
Distribution Transformers		**971,500**	**667,000**	**667,000**	**667,000**	**667,000**	**667,000**	**667,000**	**667,000**	**667,000**	**667,000**
Transformers <100kVA	Condition Compliance	285000	130000	130000	130000	130000	130000	130000	130000	130000	130000
Transformers >100kVA	Condition Compliance	385000	315000	315000	315000	315000	315000	315000	315000	315000	315000

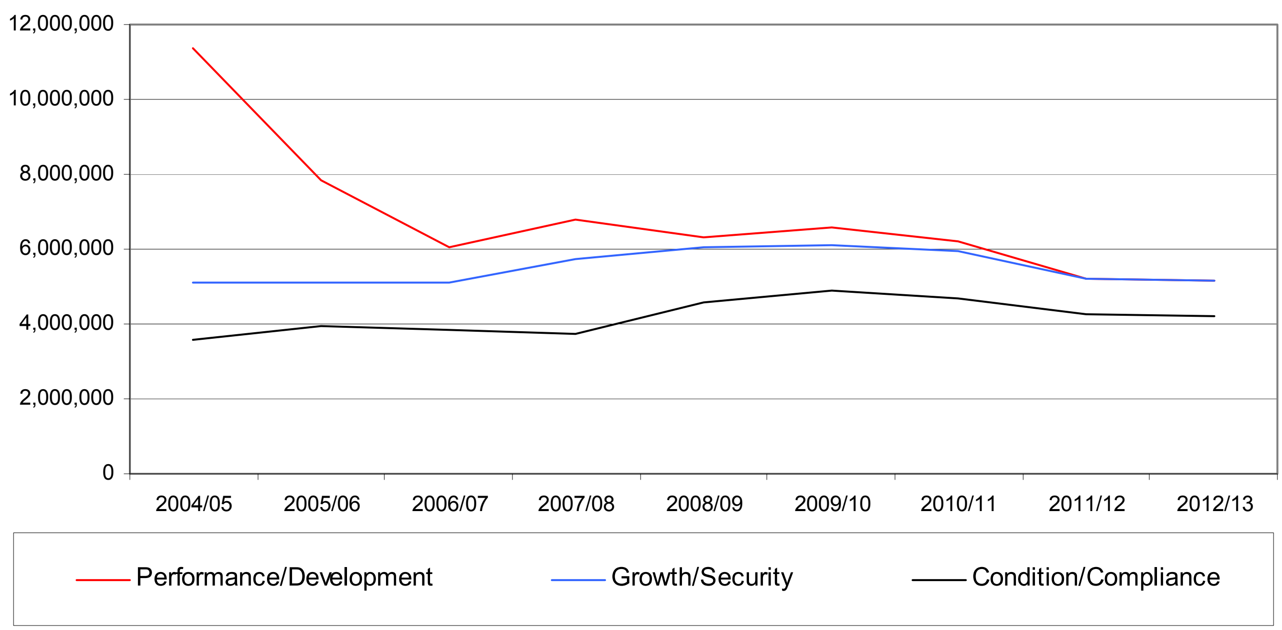
Voltage Regulator replacement	Condition Compliance	40000									
Earthing Upgrades	Condition Compliance	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Transformers Growth and Fault replacement <100kVA	Growth	107,500	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000	78,000
Transformers Growth and Fault replacement >100kVA	Growth	150,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Pole Mounted Isolation Equipment		**127,000**	**127,000**	**127,000**	**127,000**	**127,000**	**64,500**	**64,500**	**64,500**	**64,500**	**64,500**
Age Replacement of 11kV ABS's 20pa to 2008	Condition Compliance	115,000	115,000	115,000	115,000	115,000					
Age Replacement of 11kV ABS's 9pa from 2009	Condition Compliance						52,500	52,500	52,500	52,500	52,500
11kV Fuse replacement 10sets	Condition Compliance	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
11kV Ground Mounted Switchgear		**189,000**	**200,500**	**183,500**	**81,000**	**81,000**	**81,000**	**81,000**	**81,000**	**81,000**	**81,000**
New Connections	Growth	81,000	81,000	81,000	81,000	81,000	81,000	81,000	81,000	81,000	81,000
Switchgear Replacement plan	Condition Compliance	108,000	119,500	102,500							
LV Switchgear		**80,000**	**80,000**	**80,000**	**80,000**	**80,000**	**40,000**	**40,000**	**40,000**	**40,000**	**40,000**
Replace J Type LV Pillars (6 boxes p.a.)	Condition Compliance	40,000	40,000	40,000	40,000	40,000					
Allowance for New Installations	Growth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
Control and Protection		**70,000**	**13,000**	**63,000**	**105,000**	**118,000**	**108,000**	**33,000**	**51,000**	**18,000**	**118,000**
Replace Batteries / Charges	Condition Compliance	33,000	3,000	33,000	5,000	18,000	3,000	23,000	41,000	8,000	3,000
Replace AVR Relays	Condition Compliance	37,000			10,000	10,000	15,000				5000
Replace 50kV Protection	Condition Compliance			20,000							20000
Allowance for premature failure	Condition Compliance		10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Replace 11kV Protection	Condition Compliance				80,000	80,000	80,000				80000
Communications		**104,000**	**54,000**	**104,000**	**54,000**	**239,000**	**66,000**	**90,000**	**95,000**	**70,000**	**82,000**
Repeater Replacement	Condition		29,000			96,000					12000

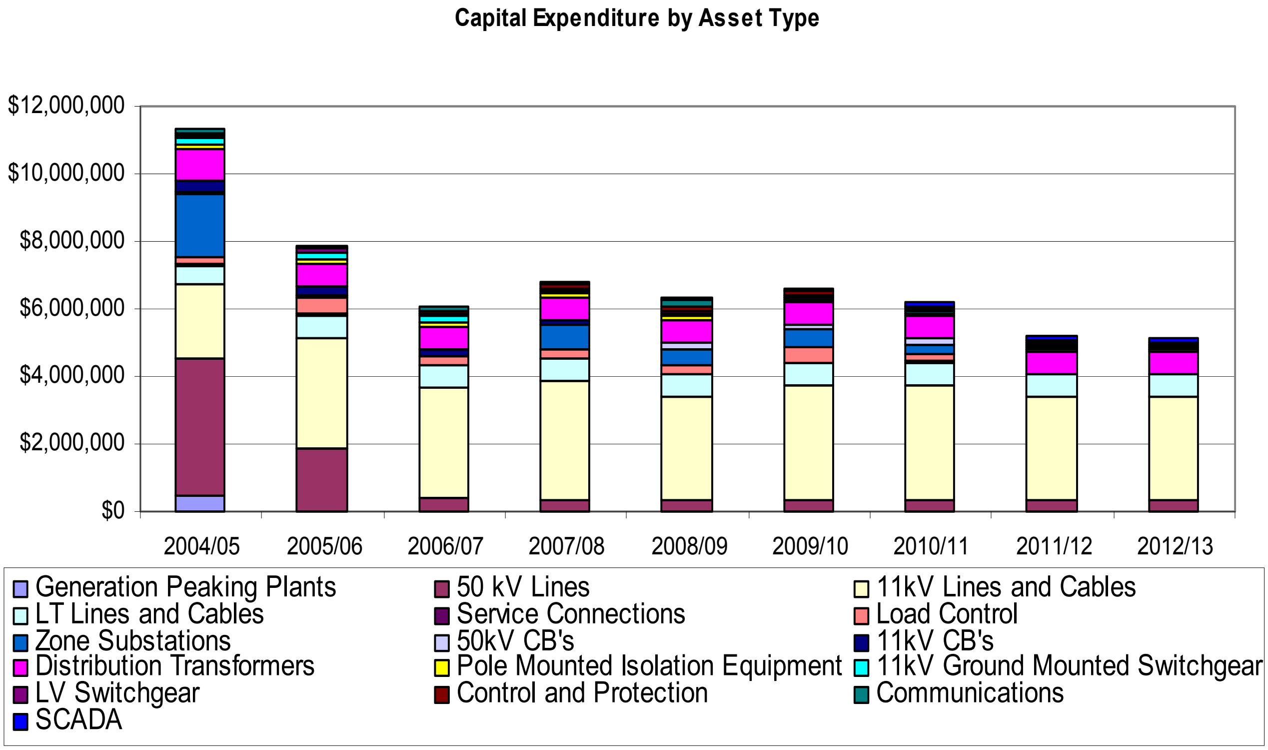
	Compliance										
Replace Links	Condition Compliance					100,000	0	20,000			
Replace Vechile RT's	Condition Compliance					7,000					
Replace Hand held Radios	Condition Compliance						20,000				
Replace Generator Carnarvon St	Condition Compliance		20,000								
Replace Generator Makaretu	Condition Compliance			10,000							
Replace Generator Arakihi	Condition Compliance			10,000							
Replace Generator Mata Rd	Condition Compliance			10,000							
Replace Generator Whakapunaki	Condition Compliance			10,000							
Replace Generator Tikitiki	Condition Compliance			10,000							
Long term development additional sites	Growth					16,000	16,000	16,000	16,000	16,000	16,000
New Technology upgrades	Growth			30,000	30,000		30,000	30,000	30,000	30,000	30,000
Isolation Facilities Upgrade	Condition Compliance		5,000			20,000			25,000		
Replace Radio Huts	Condition Compliance										
Carnarvon St to makaraka replacement Pilot	Condition Compliance	80,000									
Unplanned Replacements	Condition Compliance	24,000		24,000	24,000			24,000	24,000	24,000	24,000
SCADA		**22,000**	**22,000**	**22,000**	**40,000**	**38,000**	**38,000**	**141,000**	**141,000**	**141,000**	**25,000**
Development and Replacement on 10 Year Cycle	Condition Compliance							120,000	120,000	120,000	
Radio Repeater site RTU replacement	Condition Compliance				18,000						
Master Station Development short term	Performance	10,000	10,000	10,000	10,000	10,000	10,000				4,000
Unplanned RTU Replacement	Condition Compliance	12,000	12,000	12,000	12,000	12,000	12,000	5,000	5,000	5,000	5,000
Long term development additional sites	Performance					16,000	16,000	16,000	16,000	16,000	16,000

Capital Expenditure Profile



Capital Expenditure by Category





Total capital expenditure over the planning period is $67.3m. The expenditure profile is relatively flat with an average expenditure of almost $7m pa, indicating steady state assumptions apply. Comments on the summary by expenditure driver are made below.

Condition and Compliance

Condition and compliance driven capital expenditure averages $4.2m pa, fully funded from depreciation provisions.

Growth and Security

Growth and security driven capital expenditure averages $1.3m pa. This includes provision for the steady state customer driven network extension and capacity upgrades that cannot be avoided. The only major projects included are those where the upgrade triggers are currently exceeded. Trigger levels for growth upgrades predicted in the AMP are included in Appendix 11.2. A key feature of these projections is that while the AMP attempts to predict the impact of growth on network development, probable timings, etc. these issues are excluded from financial planning until more certainty on size and location and optimum response is evident.

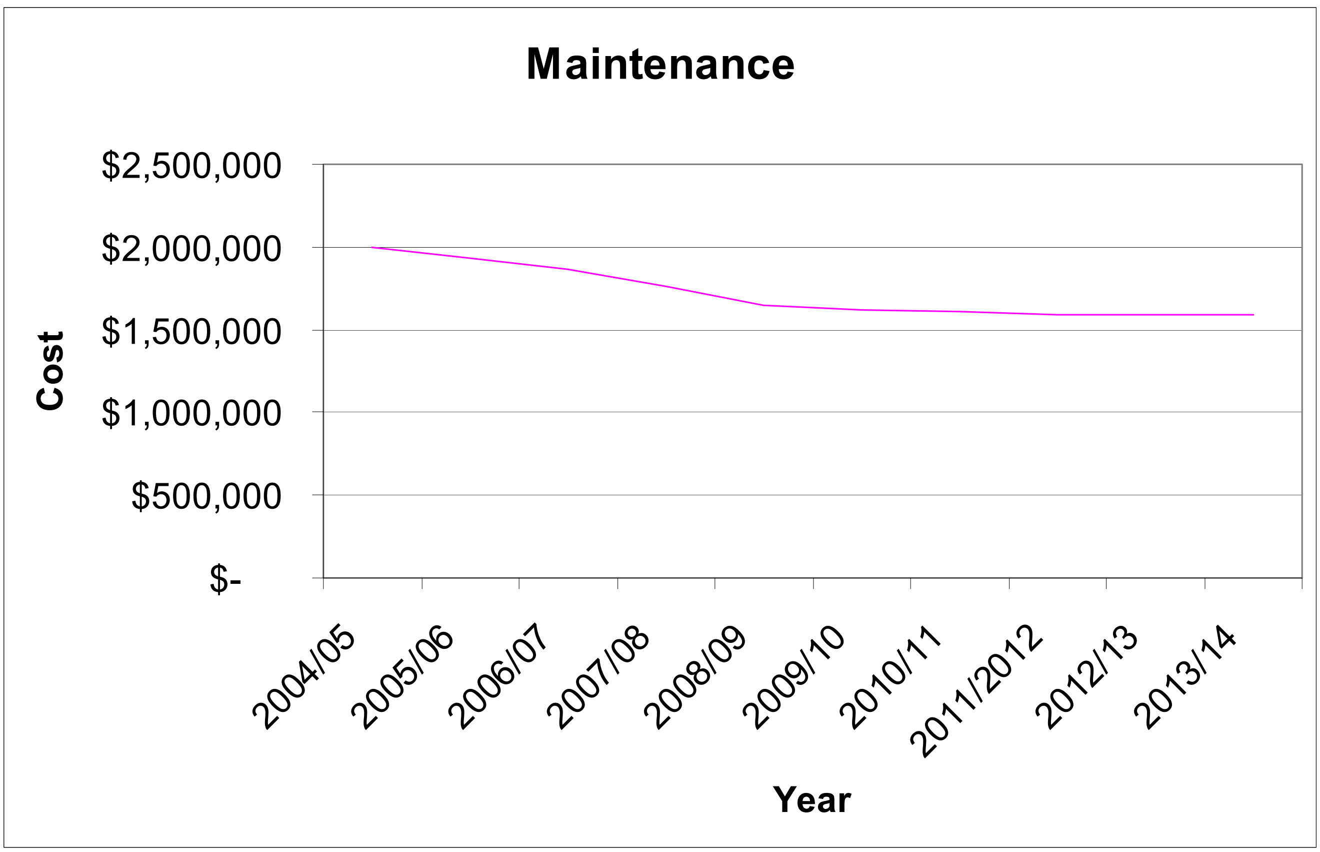
Performance and Development

Performance and new development driven capital expenditure averages $1.2 m pa, of which $0.25m pa is associated with load control expenditure on ripple relays. This work is driven by new connections, tariff changes and replacement of the pilot system as the low voltage network is replaced or upgraded. This expenditure is classified as new development because it is considered a technology enhancement. The Rural Protection and Automation Project is also a component of this expenditure. The significant portion of this expenditure in the first 3 years of the planning period is for the development of the 50kV Sub transmission and installation of additional capacity as identified in the development section.

9.1.2 Maintenance expenditure

The maintenance expenditure forecast is summarised in Table 9.1.2A by asset type, using the same categorisation presented in Section 8.0B of this AMP.

Figure 9.1.2B graphically illustrates the trend in maintenance expenditure.



9.1.2A

Maintenance 2004/05 to 2013/14

Category	Planned/Unplanned	Description	Quantity	Rate	2004/05 Planned Cost	2004/05 Unplanned Cost	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/2012	2012/13	2013/14
50kV Lines	Planned Actions	Patrols (Ground & Helicopter)	2,000	$ 12	$ 24,000		$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000	$ 24,000
50kV Lines	Planned Actions	Inspections (Climbing)	333	$ 150	$ 50,000		$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
50kV Lines	Planned Actions	Testing - Ultrasound scan (Poles)	200	$ 50	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
50kV Lines	Planned Actions	Thermovision/Ultrasound	30km	$ 480	$ 14,400		$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400	$ 14,400
50kV Lines	Unplanned Actions	Defect / Fault repairs				$ 16,200	$ 16,200	$ 14,580	$ 13,122	$ 11,810	$ 10,629	$ 9,566	$ 8,609	$ 7,748	$ 7,748	$ 7,748
50kV Lines	Unplanned Actions	Fault response (incl Helicopter)	16	$ 1,500		$ 24,300	$ 24,300	$ 22,500	$ 21,000	$ 17,715	$ 15,943	$ 14,349	$ 12,914	$ 11,623	$ 11,623	$ 11,623
50kV Lines	Unplanned Actions	Radio Interference correction	5	$ 2,000		$ 10,000	$ 10,000	$ 10,000	$ 8,000	$ 8,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000
50kV Lines	Planned Actions	Faults Management			$ 9,600		$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600	$ 9,600
11kv Lines Cables	Planned Actions	Patrols	250km	$ 120	$ 30,000		$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
11kv Lines Cables	Planned Actions	Testing -Ultrasound scan (Poles)	900	$ 50	$ 45,000		$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000
11kv Lines Cables	Planned Actions	Testing -Partial discharge (Cables)	20	$ 500	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
11kv Lines Cables	Planned Actions	Tree control program			$ 150,000		$ 150,000	$ 150,000	$ 150,000	$ 100,000	$ 100,000	$ 75,000	$ 75,000	$ 70,000	$ 70,000	$ 70,000
11kv Lines Cables	Planned Actions	Storm Contengency				$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
11kv Lines Cables	Planned Actions	Thermovision/Ultrasound	38km	$ 265	$ 10,000		$ 10,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
11kv Lines Cables	Unplanned Actions	Trees forced cutting	125	$ 324		$ 40,500	$ 40,500	$ 36,450	$ 32,805	$ 29,525	$ 26,572	$ 23,915	$ 21,523	$ 19,371	$ 19,371	$ 19,371
11kv Lines Cables	Unplanned Actions	Defect / Fault repairs				$ 254,320	$ 254,320	$ 241,431	$ 222,917	$ 208,013	$ 196,132	$ 186,825	$ 186,825	$ 186,825	$ 186,825	$ 186,825
11kv Lines Cables	Unplanned Actions	Fault response	120	$ 1,000		$ 120,000	$ 120,000	$ 120,000	$ 108,257	$ 97,431	$ 80,000	$ 80,000	$ 80,000	$ 80,000	$ 80,000	$ 80,000
11kv Lines Cables	Unplanned Actions	Control and dispatch costs				$ 20,000	$ 20,000	$ 29,160	$ 20,000	$ 20,000	$ 2,000	$ 19,132	$ 17,219	$ 15,497	$ 15,497	$ 15,497
11kv Lines Cables	Planned Actions	Faults Management			$ 118,500		$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500	$ 118,500
400v Lines Cables	Planned Actions	Patrols	50km	$ 200	$ 15,000		$ 15,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
400v Lines Cables	Planned Actions	Testing -Ultrasound scan (Poles)	300	$ 50	$ 15,000		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
400v Lines Cables	Unplanned Actions	Defect / Fault repairs				$ 52,650	$ 52,650	$ 52,650	$ 47,385	$ 47,385	$ 42,647	$ 42,647	$ 38,382	$ 38,382	$ 34,544	$ 34,544
400v Lines Cables	Unplanned Actions	Fault response	112	$ 250		$ 28,000	$ 28,000	$ 25,515	$ 22,964	$ 20,667	$ 18,600	$ 16,740	$ 15,066	$ 13,560	$ 13,560	$ 13,560
400v Lines Cables	Planned Actions	Faults Management			$ 19,000		$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000	$ 19,000
Service Connections	Planned Actions	Patrols/inspection	500	$ 10	$ 5,000		$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Service Connections	Unplanned Actions	Voltage Checks/Complaints	100	$ 324		$ 32,400	$ 32,400	$ 29,160	$ 26,244	$ 23,620	$ 21,258	$ 19,132	$ 17,219	$ 15,497	$ 15,497	$ 15,497
Load Control	Planned Actions	Injection plant testing	2	$ 4,000	$ 8,000		$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000
Load Control	Unplanned Actions	Defect repairs / replacement costs				$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Load Control	Unplanned Actions	Fault response (Pilot circuits)	43	$ 250		$ 10,700	$ 10,700	$ 10,700	$ 9,842	$ 8,857	$ -	$ -	$ -	$ -	$ -	$ -
Load Control	Planned Actions	Faults Management			$ 3,800		$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800	$ 3,800
Zone Substations	Planned Actions	3 Monthly Inspections	100	$ 250	$ 25,000		$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Zone Substations	Planned Actions	Grounds Maintenance	240	$ 125	$ 30,000		$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
Zone Substations	Planned Actions	Safety Equipment Inspections and testing	40	$ 250	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Zone Substations	Planned Actions	Occupational Health and safety Inspection	20	$ 250	$ 5,000		$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Zone Substations	Planned Actions	Thermovision AND Ultrasound Inspections	20	$ 250	$ 5,000		$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Zone Substations	Planned Actions	Transformer Overhauls			$ 30,000		$ 30,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Zone Substations	Planned Actions	Average Routine Maintenance			$ 60,000		$ 60,000	$ 60,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000
Zone Substations	Unplanned Actions	Defect / Fault repairs				$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Zone Substations	Unplanned Actions	Fault response				$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100	$ 4,100
Zone Substations	Planned Actions	Faults Management			$ 5,900		$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900	$ 5,900
Zone Substation Transformers	Planned Actions	DGA furrow tests p.a.	10	$ 1,000	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Zone Substation Transformers	Planned Actions	Average tap changer overhauls 1 unit p.a.	1	$ 15,000	$ 15,000		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Zone Substation Transformers	Planned Actions	Average oil processing 2 p.a.	2	$ 6,000	$ 12,000		$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000
Circuit Breakers	Planned Actions	Annual Inspections (Rural CB's)	40	$ 250	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Circuit Breakers	Planned Actions	Average Routine Maintenance (Rural CB's)	8	$ 2,500	$ 20,000		$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Circuit Breakers	Planned Actions	Expenditure Component Rural Automation Project			$ 21,000		$ 21,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Circuit Breakers	Unplanned Actions	Defect /Fault repairs	5	$ 3,000		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Transformers	Planned Actions	Refurbishment <100kVA	5	$ 1,400	$ 7,500		$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500
Transformers	Planned Actions	Refurbishment >100kVA	2	$ 4,000	$ 8,000		$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000
Transformers	Planned Actions	Painting Ground mount/graffiti	20	$ 150	$ 3,000		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
Transformers	Planned Actions	Inspection and MDI's	200	$ 50	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Transformers	Planned Actions	Oil Handling /filtering /TX disposal			$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Transformers	Planned Actions	Transformer 5 yearly Compliance checks	100	$ 50	$ 5,000		$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Transformers	Planned Actions	Earth testing	1000	$ 45	$ 45,000		$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000
Transformers	Planned Actions	Earthing system repairs	60	$ 500	$ 30,000		$ 30,000	$ 30,000	$ 30,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Transformers	Planned Actions	Oil Analysis	20	$ 300	$ 6,000		$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000
Transformers	Unplanned Actions	Defect /Fault repairs				$ 16,200	$ 16,200	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
Transformers	Unplanned Actions	Vegetation clearance				$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Transformers	Planned Actions	Faults Management			$ 3,700		$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700	$ 3,700
Pole Mounted Isolation Equipmen	Planned Actions	Inspection and Testing	40	$ 300	$ 12,000		$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000
Pole Mounted Isolation Equipmen	Unplanned Actions	Defect /Fault repairs				$ 12,960	$ 12,960	$ 11,664	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Pole Mounted Isolation Equipmen	Planned Actions	Faults Management			$ 3,000		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
11kV Switchgear Ground Mount	Planned Actions	Annual Inspection	167	$ 60	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
11kV Switchgear Ground Mount	Planned Actions	Average Magnefix Cleaning p.a.	0	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11kV Switchgear Ground Mount	Planned Actions	Average Switch maintenance p.a.	18	$ 1,000	$ 18,000		$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000
11kV Switchgear Ground Mount	Planned Actions	5 Yearly Service Inspection	7	$ 3,000	$ 20,000		$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
11kV Switchgear Ground Mount	Planned Actions	Thermoscan Partial Discharge	80	$ 125	$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
11kV Switchgear Ground Mount	Unplanned Actions	Defect /Fault repairs				$ 11,400	$ 11,400	$ 11,400	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
11kV Switchgear Ground Mount	Planned Actions	ABS Removal (refer AMP)	100	$ 400	$ 40,000	$ -	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ -	$ -	$ -	$ -	$ -	$ -
11kV Switchgear Ground Mount	Planned Actions	Faults Management			$ 3,000		$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
LV Switchgear	Planned Actions	Inspections/servicing	50	$ 300	$ 15,000		$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
LV Switchgear	Unplanned Actions	Defect /Fault repairs				$ 9,100	$ 9,100	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ 8,000
LV Switchgear	Unplanned Actions	Painting				$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000
Communications	Planned Actions	Maintenance/Calibration			$ 35,000		$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000	$ 35,000
Communications	Planned Actions	Track Maintenance			$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Communications	Planned Actions	Hut Maintenance			$ 4,000		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000
Communications	Planned Actions	Radio Licences			$ 13,000		$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000	$ 13,000
Communications	Unplanned Actions	Defect/Fault repairs				$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000
SCADA	Planned Actions	Support fees			$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
SCADA	Planned Actions	Software Licences			$ 5,000		$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
SCADA	Planned Actions	SCADA maintenance allowance			$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
SCADA	Planned Actions	Point to point testing of Digital IO			$ 10,000		$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
SCADA	Planned Actions	Configuration and file alterations			$ 6,000		$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
SCADA	Unplanned Actions	Defect/Fault repairs				$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
					$ 1,158,400	$ 838,830	$ 1,997,230	$ 1,930,710	$ 1,863,034	$ 1,763,521	$ 1,647,281	$ 1,620,806	$ 1,606,258	$ 1,592,003	$ 1,588,165	$ 1,588,165

The total maintenance expenditure over the planning period is $17.2m, with expenditure reducing steadily from $1.99m in 2004/05 to $1.59m in 2013/14.

This is within the company's direct cost per km performance target. This AMP identifies ENL's assets as being in their age replacement phase of their life cycle. The management tactic is to therefore replace rather than to continue with a heavy maintenance strategy. The expected improvement in average asset condition will lift performance and allow low maintenance expenditure to be sustained.

9.2 Funding Strategy and Financial Plan

ENL prepares a separate 10 year Financial Plan to:

- Identify the funding requirements needed to deliver on strategic objectives
- Demonstrate that long term financial trends meet business performance requirements of the shareholder, and to
- Demonstrate to consumers and the regulatory authorities that both asset management service and pricing objectives can be delivered upon.

Comprehensive financial statements are presented in the 10 Year Financial Plan.

This AMP underpins network related expenditure and identifies the basis for asset management service objectives.

10.0 AMP IMPROVEMENT AND MONITORING

ENL is undertaking a number of major asset management improvement initiatives which commenced in 2002. In generally the physical work completed is in line with previous plans. However variances in timing have occurred which have pushed out completion dates due to lower than forecast growth. Where changes to the development plans described in previous Asset Management Plans have occurred these have been updated in the current plan. The most significant initiates and changes are described briefly here.

10.1 Asset Information

Improvement of asset information systems and data confidence is fundamental to ENL's knowledge and management of its assets.

- GIS Data Conversion
  Geographic Information System software was evaluated and a package appropriate to ENL's needs purchased in 2001. The system was put online in February 2003 following the data conversion. Final stages of data auditing and correction were completed in April 2004 subsequent to which the benefits of more integrated information systems can be realised the first of which being the ODV as at 31 March 2004. Utilising the built in measurement tools of the new GIS software line length information has been updated to reflect the improved accuracy. Addition data work is required for LV assets including Distribution Pillars ,Link boxes and Customer connection details.

- Improved Survival Forecasting
  Improved survival forecasting information is dependant on ongoing accuracy improvement of data relating to assets and their assessed condition. Successive Asset Management plans are adjusted to reflect the ongoing improvements.

- Substation Drawings, Equipment Manuals and Records.
  Drawings for substation equipment are produced using the Microstation cad package.
  Work is in progress to convert older hard copies to the electronic format and is due for completion in the long term. The drawings include electrical wiring, schematics and mechanical construction drawings. Electrical wiring and schematic drawings are maintained on CD for fault response personal to aid prompt repair times following equipment faults.
  Equipment manuals are maintained for all major equipment. Newer manuals are maintained in electronic format and maintenance contractors hold copies. Equipment inspection and maintenance records are maintained in electronic format for all relevant equipment not covered by the Geographical Information system.

10.2 Asset Management Processes

The following improvements are directed at improving the effectiveness of asset management processes and the confidence levels ascribed to the actions derived in the AMP.

- Risk Quantification
  Development of a more comprehensive risk management plan for the company is underway together with review of the current assessments and supporting analysis. This review, by an external party is scheduled to be completed in July 2004 recommendations and improvements will be incorporated into future revisions of the AMP.

- Load Growth Forecasting Models
  Ongoing development of the more accurate predictive load forecasting model described in Section 5.0 will be continued. The aim of the model is to minimise reliance on historical data and trending.

- Quality Management
  A formalised Quality Management System covering all aspects of ENL's business initially to be developed by 2002/03 was delayed by changes to the Company and management structure. The system is now being developed by EIL and is intended to consolidate corporate, compliance, contractor management, distribution control, safety and engineering manuals, standards and policies in a coordinated set of documents and formally implement quality monitoring, continuous improvement and audit functions. The scope will include all core asset management activities.

10.3 Monitoring and Review

ENL conducts both internal and external reviews of its AMP.

Internal improvement is the primary responsibility of the asset management team and is continuous as the AMP is updated during the normal business planning cycle.

Statutory external monitoring will be undertaken by the Commerce Commission from 2004 to confirm compliance with mandatory disclosure standards. Other external audits are undertaken at regular intervals and are directed at:

- Confirmation of the validity of technical content
- Assessment of asset management performance relative to others and to best practice
- Identification of relative improvements during business cycles and improvement priorities
- Assisting the internal asset management team implement improvement

ENL regularly endeavours to benchmark its asset management practices against other Lines Businesses and align with customer consultation inputs, in order to more effectively target appropriate improvements, standards and levels of service.

11. APPENDICES

11.1 Security Guidelines – Network Component Provisions

A Transmission and Sub-transmission

- N-1 security will be provided for all lines, cables, and equipment where loading exceeds 12MVA.
- CB's will be rated at twice maximum load to enable carrying of adjacent feeder loads.
- 33kV and 50kV CB's shall only be fitted with bypassing arrangements where supplying a spur line. This is to allow maintenance/repair with the substation(s) on-line.

B Zone Substations

- Zone substation transformers.
  - ➢ Loading is to comply with IEC354. This permits overloading beyond nominal ratings under specified ambient and cyclical conditions. Thus the duration of restoration following a first interruption will result in no ageing beyond design provisions. Overloading of transformers such that ageing occurs will only be permitted for a second contingent event of up to 1 hour.
  - ➢ Loading shall not exceed 150% of the transformers design rating.
  - ➢ All connections and auxiliary equipment shall be rated for continuous operation at maximum load levels.
  - ➢ Zone transformers will be rated to support a minimum of half the loading of neighbouring zones.
  - ➢ Installation of forced/assisted cooling will be used in preference to dual transformer installation or capacity upgrades where overload is required beyond IEC354 for contingent events.
  - ➢ Zone substations carrying normal load in excess of 12MVA will be of dual transformer designs if it is unlikely that neighboring substations or feeder circuits will be able to support that substation after allowing for 10 years growth.
- 11kV switch panels will have a split bus arrangement where maximum demand is likely to exceed 6MVA. In single transformer substations the transformer and the 6MVA 11kV tie line to the adjacent substation shall be connected on opposite sides of the bus. This ensures delivery of supply capacity to a zone if one bus is out of service.
- Urban 11kV feeder CB's shall not be normally loaded beyond 4MVA and allow excess capacity availability to 6MVA. The tie feeder between Carnarvon St and the Port area requires an 8MVA rating.
- Feeder cables from CB's must be rated to match CB excess capacity requirements: typically 6MVA in the urban/CBD/industrial area. In rural areas feeder cables shall be rated to 3MVA.

- All feeder circuits must have a tie switch external to the substation to another circuit from the opposite side of the bus or ties to a feeder from an adjacent substation.

C Distribution

- 11kV circuits provide security via excess capacity, interconnection and isolation ability, i.e. the focus is on restoration speed and contingency provision as opposed to un-interruptible supply. Generally excess capacity and provision of mobile generation provide LV circuit security. In key commercial and industrial areas LV interconnection may be appropriate. Generally the following provisions shall apply.
- The installation of remote or automatically operated equipment shall be governed by the response times determined in Table 2.
- 11kV Pad mounted switchgear provisions
  - No more than 3 transformers supplied from 1 switchboard without bus section
  - Not more than 1MVA fed from switchgear supplied from a single cable circuit (excluding industrial situations)
  - No more than 1MVA of installed transformers and associated switchgear cascaded with no back feed
- Not more than 1 cable circuit connected directly to the bus of a switchboard arrangement.
- In rural areas an air break switch will be installed as an isolation point every 50 customers or 25km of downstream circuit
- Cables will be designed with 33% excess capacity to enable sharing of half the load of the connecting circuit where there are two alternative supply routes.
- Where overhead lines have tie capability (except ABC) they will be permitted to operate to 120% capacity in emergencies. Therefore they will be designed for sag and clearances appropriate to the maximum conductor operating temperature rather than 50^0C provided this does not exceed 75^0C.
- Lines will not be permitted to have more than 2% losses at installation.
- Spur assets (lines, cables, transformers) that cannot be supported via the LV network will have provisions for quick connect standby generation if normal loading exceeds 200kVA.
- Distribution transformers (<2500kVA) will be permitted to overload to the ratings of IEC354.
- In Commercial and Industrial areas
  - General distribution transformers will normally be 500kVA. All cables shall be rated to allow loading of the transformer to 120%. This would provide overload capacity for 6 hours in winter peak areas at 20^0C (10 hours at 10^0C) and for 3 hours in summer peak areas at 30^0C given an initial loading at 80%. Actual load profiles for a given transformer where initial loading is less than 80% will enable extension to the period of overload.
  - LV interconnection shall normally be specified to allow for an out of service condition of an intermediate transformer. Where LV interconnected, transformers should not

exceed, other than for short duration's of <1hr, 80% of their rating under normal operating conditions.

- LV runs from transformer to an open tie point should not exceed 200m (400m from transformer to transformer).
- Loads in industrial areas > 50kVA should have a dedicated LV feed.

- In urban domestic supply areas including small commercial areas located predominantly within an urban area
  - Transformer size should be standardised to 200kVA in winter peak areas with cables rated to allow loading of the transformer to 133% and in summer peak areas 300kVA with transformers with cables rated to allow loading of the transformer to 100%.
  - Each LV feeder should not be supporting in excess of 25 domestic supplies assuming an After Diversity Maximum demand of 3kVA
  - LV interconnection would normally only be provided where a small commercial shopping centre is located within a predominately urban area. 300kVA transformers may be required.
  - Provision of quick mobile substation connections to the LV is preferred to the provision of LV interconnection.
- Transformers must be able to be isolated from LV bus bars via incomer links where LV interconnection to another transformer is provided.

11.2 Statement of Growth and Security Constraint Triggers

INTRODUCTION

Expenditure forecasts exclude growth expenditure until specifically approved by ENL's Board. The following documents the loading trigger points at which security standards will be compromised.

Minor distribution capacity upgrades are excluded.

Carnarvon Street
Substation constrained to 12.5MW before full n-1 security is necessary. This will require closing the 50kV ring from the Port to Carnarvon Street. Load will be shifted to neighbouring substations before transformer upgrade is considered. Growth will be shifted to Kaiti, Port and Parkinson Street in order to prevent this substation becoming too large for its neighbours to support.

Kaiti
Substation is constrained by its 11kV tie capacity to other substations in the event of its 50kV line or single 12.5MW transformer failing. When total load on Kaiti and the Port sub exceeds 12.5MW the 50kV ring to Carnarvon Street should be closed.

Parkinson Street
A second 12.5MW transformer is needed when load at Parkinson Street and the contingency capacity needed to support any one of the three neighbouring substations (Carnarvon, Makaraka, Matawhero) exceeds 12.5MW.

Matawhero
A 50kV ring needs to be closed between Matawhero and Parkinson Street when load exceeds 7MW due to constraints on the 11kV network.

Makaraka/JNL
A second 12.5MW transformer is required when load plus the contingent capacity to either Matawhero or Parkinson Street exceeds 12.5MW. In the very long term reconductoring of the two 50kV circuits between Gisborne and Makaraka may be necessary when the combined load at Parkinson, Makaraka, Matawhero and Patutahi exceeds 30MW.

Patutahi
The strategic importance of this substation has been replaced by Makaraka. Transformers can be reduced from two 5MW banks to a single 5MW transformer when opportunistic. Growth on the 11kV network in the Muriwai/Manutuke areas is to be supported via feeder development from Matawhero.

Mahia
Transformer capacity at Blacks Pad needs to be upgraded to 2.5MW with OLTC when load plus 300kVA contingent support for Nuhaka/Morere exceeds 1.5MW. However voltage at Mahia and Mahunga is likely to be a more pressing issue in this part of the network. A

Generator will provide temporary relief until the 33kV line is extended to Opuatama and a new substation built. The 2.5MW OLTC transformer at Wairoa would be used for this purpose and a larger unit will be required at Wairoa.

Frasertown/Raupunga
This line is voltage constrained and economics dictate a very incremental approach to relieving the constraints. Establishing an 11kV supply point at Waihi Dam to support the mid-point of the ring is the most cost-effective solution especially if co-ordinated with conversion of the Waihi line to 33kV. This action rationalises sub-transmission voltages and reduces the number of transformers on the subtransmission network.

Wairoa Township
Generally this area is constrained in terms of 11kV capacity. An incremental step increase will be necessary should medium industry additions or Affco upgrades occur. (1 to 2 MW Trigger). Rationalisation of the Waihi line to 33kV prepares an upgrade path via 33kV to Affco or the Wairoa CBD.

Tatapouri
When load on the Dalton Feeder (Wainui Beach area) at Kaiti exceeds 2MW the 50 km distance between Kaiti and the next substation at Tolaga is too large for the voltage regulator at Tatapouri to maintain acceptable voltage. An intermediate substation at Whangara is a lower cost solution to conductor upgrade and extra voltage support.

11.3 11kV Feeder Loss Analysis

	Substation	Feeder	Load KVA	Losses KVA	% Losses
0101	Te Araroa	AWATERE	165	16	10%
0102	Te Araroa	HICKS BAY	228	24.7	11%
0103	Te Araroa	TE ARAROA	191	4	2%
0201	Ruatoria	RUATORIA	472	28	6%
0204	Ruatoria	MAKARIKA	212	24	11%
0206	Ruatoria	TIKI-TIKI	420	23	5%
0301	Tokomaru Bay	INLAND	136	10.2	8%
0302	Tokomaru Bay	SEASIDE	237	8.3	4%
0304	Tokomaru Bay	MATA RD	527	59	11%
0401	Tolaga Bay	TOKO-TIE	0	0	
0402	Tolaga Bay	TOWN	159	1	1%
0403	Tolaga Bay	ROTOTAHI	305	23	8%
0404	Tolaga Bay	TAUWHAREPARE	353	56	16%
0501	KAITI	HERSCHELL	576	9	2%
0502	KAITI	DALTON	1257	59	5%
0503	KAITI	TAMARAU	2117	51	2%
0504	KAITI	WAINUI	1241	22	2%
0505	KAITI	DE LATOUR	2857	52	2%
0506	KAITI	WHANGARA	-	-	-
0601	CARNARVON	KAHUTIA	2000	39	2%
0602	CARNARVON	CITY	2390	40	2%
0603	CARNARVON	WATTIES	1320	92	7%
0604	CARNARVON	ANZAC ST	900	33	4%
0605	CARNARVON	CHILDERS RD	2207	70	3%
0606	CARNARVON	AWAPUNI RD	870	30	3%
0607	CARNARVON	GLADSTONE RD	2320	37	2%
0608	CARNARVON	ABERDEEN RD	2570	48	2%
0701	PARKINSON	LYTTON RD	1567	36	2%
0702	PARKINSON	WILLOWS RD	1157	30	3%
0703	PARKINSON	ELGIN	1999	47	2%
0704	PARKINSON	JNL	4076	234	6%
0705	PARKINSON	INNES ST	225	5	2%
0802	MAKARAKA	CAMPION	-	-	-
0803	MAKARAKA	NELSON RD	-	-	-
0804	MAKARAKA	HAISMAN RD	-	-	-
0805	MAKARAKA	BUSHMERE RD	-	-	-
0902	PATUTAHI	LAVENHAM RD	475	18	4%
0903	PATUTAHI	WAIMATA	650	33	5%
0905	PATUTAHI	MURIWAI	536	26	5%
0906	PATUTAHI	TE ARAI	284	32	11%
1001	PEHERI	W O KURI	154	6	4%
1002	PEHERI	PARIKANAPA	50	9.8	20%
1003	PEHERI	TINIROTO	157	24.8	16%
1004	PEHERI	TAHUNGA	62	12	19%

	Substation	Feeder	Load KVA	Losses KVA	% Losses
11	NGATAPA	Total Substation	377	44	12%
1201	PUHA	WHATATUTU	365	34	9%
1202	PUHA	KANAKANAIA	270	23	9%
1203	PUHA	TE KARAKA	195	10	5%
1204	PUHA	MATAWAI	629	81	13%
20	TUAI	Total Substation	1000	95	10%
2003	TUAI	RUAKITURI	460	69	15%
3101	WAIROA	RAUPUNGA	1057	126	12%
3102	WAIROA	FRASERTOWN	540	85	16%
3103	WAIROA	AWATERE	300	6	2%
3201	KIWI	BRICKWORKS	157	26	17%
3202	KIWI	AFFCO	3248	120	4%
3203	KIWI	NUHAKA	811	45	6%
3204	KIWI	BOROUGH ONE	1192	139	12%
3205	KIWI	BOROUGH TWO	1006	50	5%
3401	TAHAENUI	MORERE	300	31	10%
3301	BLACKS PAD	MAHIA	700	90	12%

11.4 Network Investment Policy

The East Coast will face a number of significant transmission and distribution network constraints as load grows over the next 10 years.

The uncertainty associated with forestry-driven load growth, the national gas reserves, technology advances etc. over the next 10 years present substantial investment risk for traditional network solutions which have lives and paybacks exceeding 10 years.

Security issues appear early in the development of constraints, yet generally only present risks that are low probability and short duration. Addressing these issues through doubling assets/capacity so that full redundancy can be provided is inefficient and inappropriate in the current risk environment.

Consequently Eastland Network Ltd seeks non-traditional i.e. non-wires and poles solutions to addressing constraint issues. The objective is to solve the particular constraint i.e. security or growth capacity, in increments that match the magnitude of the issue as it develops and to deliver solutions as closely as possible to the time the issue arises.

The long term strategy will be the appropriate application of distributed generation to provide new capacity beyond the capability of existing network assets. This will require a portfolio of diverse generation sources and load management options.

11.5 Valuation Targets by Network Segment

The ODRC per connection is used as an indicator of variance between zone substations in the investment required to deliver the same levels of service. The NZ average is $2,563 per ICP. Some variance is expected between urban and rural substations. However when values in rural areas exceed this average by more than 100%, it is unlikely that economics can be equalised via tariff differentials.

Following the high investment in 2001 Eastland Network Ltd's ODRC per connection is now $2,577 which is very close to the NZ average. Only 2 zone substations have an ODRC/ICP greater than the desirable maximum of $5,126. These are:

- Te Araroa at $5,790 i.e. 13% over investment, and

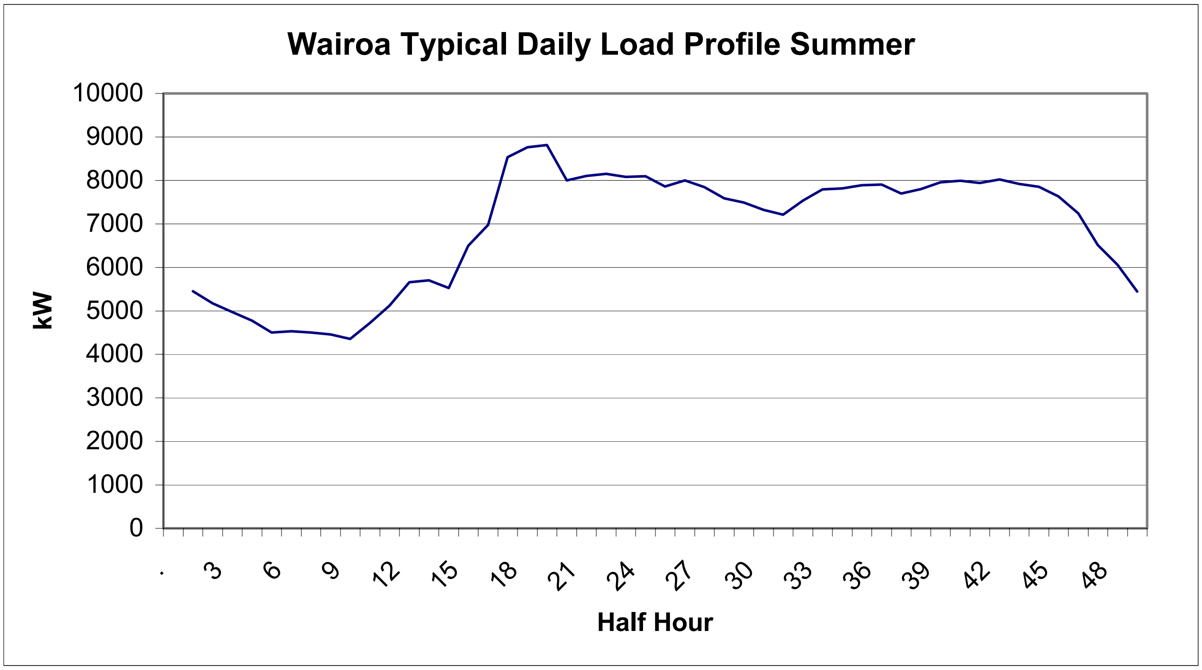
- Pehiri at $6,961 i.e. 36% over investment.

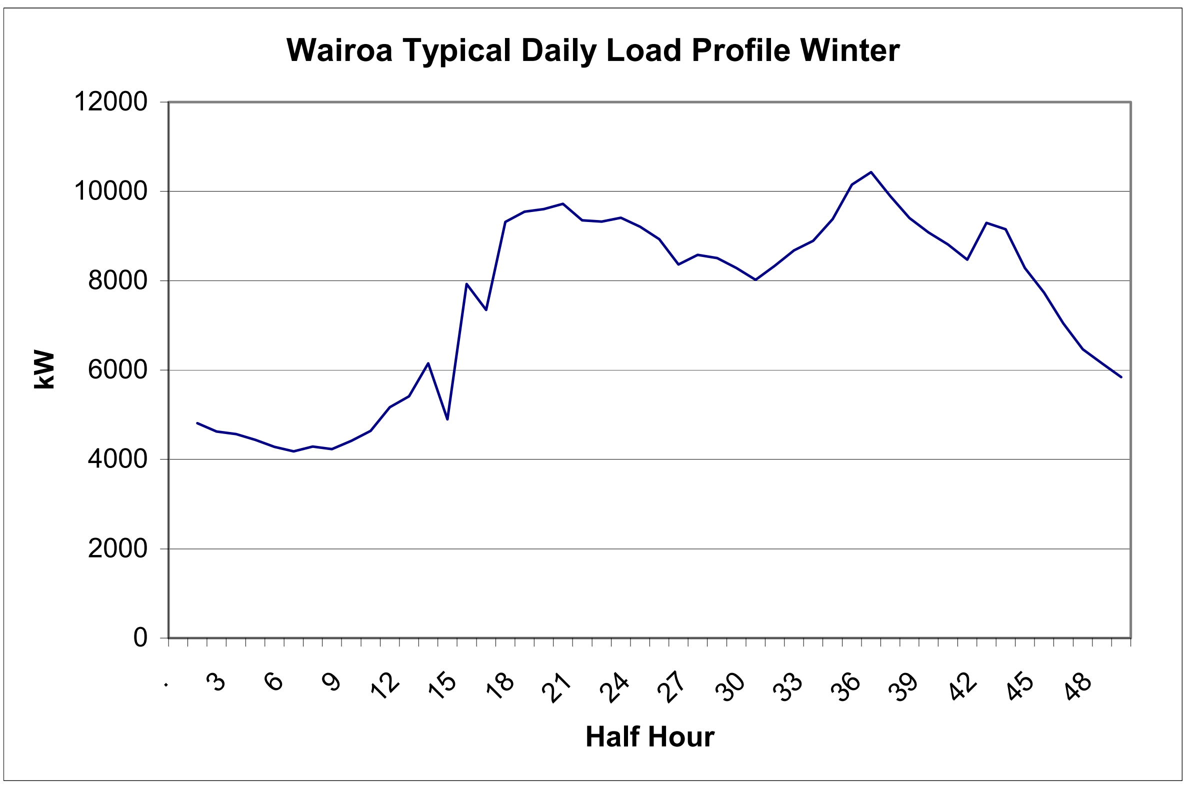
Both these substations have been constructed in the past 10 years and assets are therefore newer than average. Their value will correct itself via normal depreciation. If the quarry load could be removed from Pehiri it is possible that this substation could be eliminated.

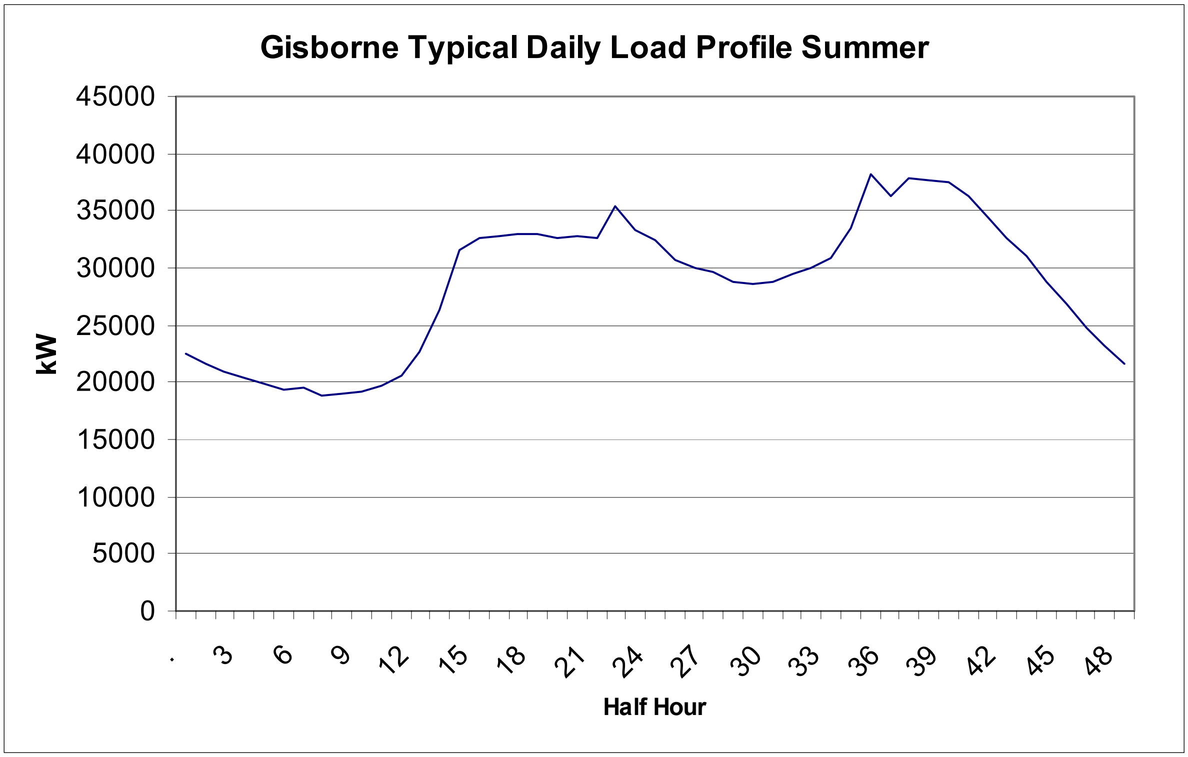
The valuation imbalance is a lot less significant than in the past indicating the previous initiatives to reduce assets or to leave them to age in rural areas have been successful. Similarly new investment has concentrated on urban areas.

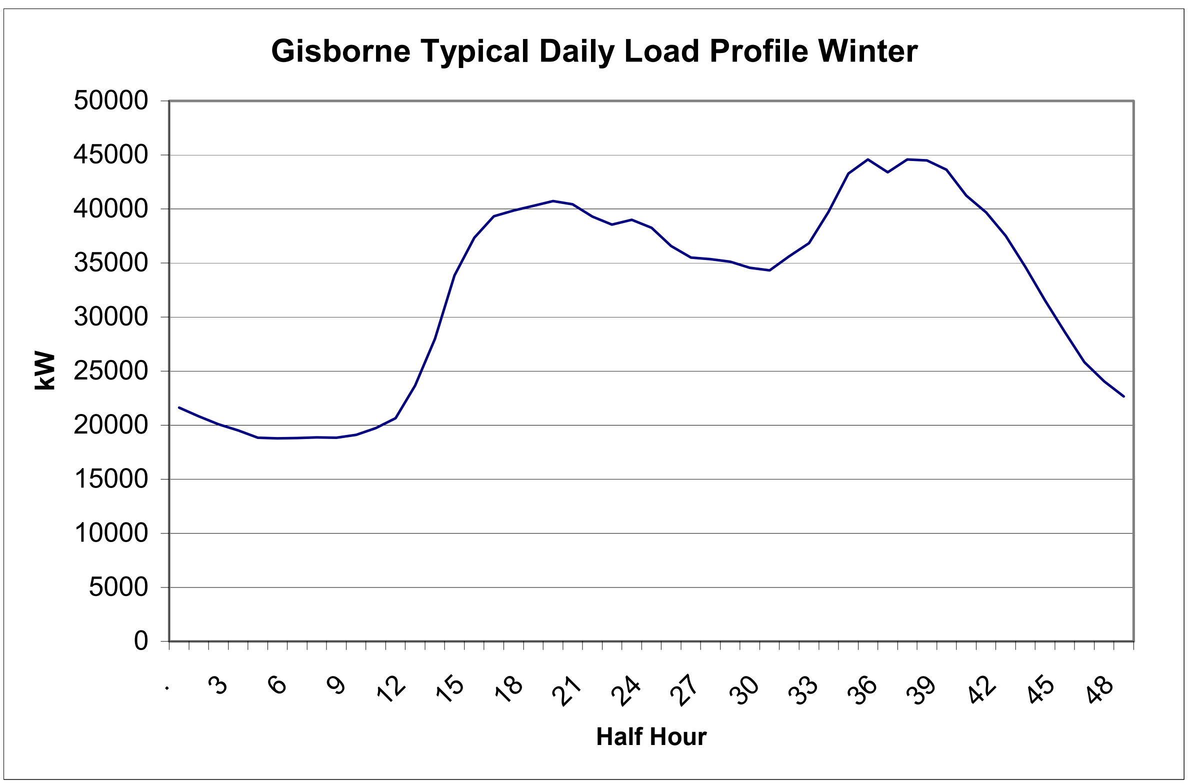
When indicators of low investment are considered those that are substantially below the average are: Kaiti, Carnarvon St. and Blacks Pad. These three substations happen to be the most constrained and so the indicators are signalling the potential to invest realising high economic value.

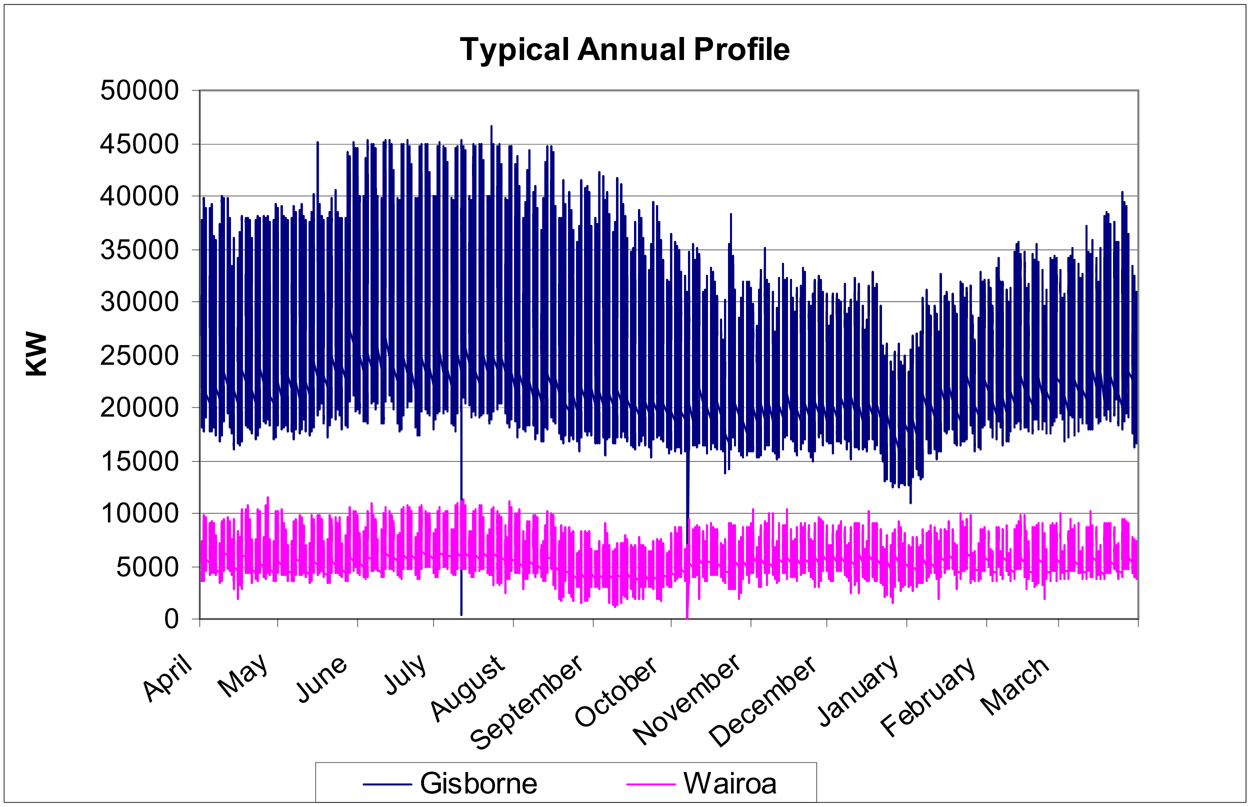
11.6 Typical Daily Load Curves






Gisborne Typical Daily Load Profile Summer
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
kW
3
6
9
12
15
18
21
24
27
30
33
36
39
42
45
48
Half Hour


Gisborne Typical Daily Load Profile Winter
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
kW
3
6
9
12
15
18
21
24
27
30
33
36
39
42
45
48
Half Hour



Typical Annual Profile
KW
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
April
May
June
July
August
September
October
November
December
January
February
March
Gisborne
Wairoa

11.7 Pricing Policy

1. **The Pricing Methodology developed for Line Function Services will deliver compliance with Targeted Control Regime Pricing Threshold requirements.**

As determined by the assessments undertaken to date, ENL is compliant with all requirements of the Price Path Threshold.

2. **Pricing for Line Function Services will be set to deliver at a return on network assets valued at the regulators ODV equivalent to the companies WACC.**

WACC is currently the industry view of what the regulatory attention line is. WACC on ODV is ENL's shareholders view of adequate return on their investment.

3. **Non-regulated services will be separated from network pricing where possible and charged for at a rate that delivers 12 % return on the portion of shareholders funds related to non-network asset.**

Non-regulated services are not constrained and therefore higher returns will be targeted. As these services are non-core business those that do not support higher returns may be exit targets.

4. **Transmission pricing will be disaggregated from distribution pricing but averaged across all Grid Exit Points.**

Dis-aggregation of transmission and distribution costs allows easier defence and pass through of Transpower-driven price increases. Preserving pricing signals allows the option of Conveyance Agreements (instead of an interposed UoSA) with unbundled line charges presented on the consumers account. There is no advantage in disaggregating GXP pricing. Averaging reduces complexity of tariffs and has high public acceptance.

5. **No profit margin will be added to Transpower's costs other than legitimate on-costs/risks of repackaging/variabilising charges.**

UoSA specifically excludes margins on Transpower charges.

6. **Transmission pricing will include signalling of avoided transmission benefit for generation.**

Adding avoided transmission cost signals leads to efficient investment decisions for ENL and other investors.

7. **Transmission pricing will include return on ENL provided assets installed as an alternative to transmission investment.**

If ENL invests in transmission asset it will justify investment on lower transmission costs. The net remaining costs are a transmission cost.

8. **Load control will be considered as an alternative to transmission investment and revenue allocated to it in the same manner as generation receives an avoided transmission cost benefit.**

Load control provides the same benefits as generation. As a lower cost solution its maximum utilisation needs to be signalled.

9. **Rebates will not be netted from Transpower charges so that the "cost of transmission" signal is preserved. They will be treated as other income and therefore will still reduce total revenue requirement.**

Rental Rebates are generated in the market and are not a transmission cost driver. They are also shortly to be replaced by FTR's (Financial Transmission Rights) which ENL is unlikely to invest in. To ensure rebates do not distort pricing and avoid the un-recovery risk if they are removed during a pricing year they are to be treated independently.

10. **While load growth trends are positive the company will pursue a greater than 80% exposure in its revenue stream to variable pricing. No load growth will be modelled in revenue forecasts for the coming year such that the lag between revenue and load growth is captured.**

Maximising variable recovery allows the company to benefit from windfall revenue growth resulting from load growth. Some fixed charges are necessary for optimum efficiency in pricing to signal sunk costs but this has been corrupted by regulatory constraints.

10. **Time of Use tariffs are considered the most effective means of signalling demand driven costs and constraints.**

TOU tariffs can be matched more closely to demand which drives ENL's costs and investment decisions.

11. **Charges will be disaggregated to individual ICP level.**

ICP level pricing allows allocation of costs over the range of domestic load groups. It also provides an incentive for ENL to manage line losses.

12. **Fixed charges will be made on the basis of one charge per ICP.**

One ICP – one charge facilitates differentiation of load groups, making registry management and customer switching easier.

13. **Street lighting will have ICP's defined at every point of feed/control by ENL i.e. not individual lights.**

The control point is the last consistent point of asset ownership demarcation. ENL wishes to avoid responsibility for street lighting asset.

14. For the purpose of regulation compliance ENL will differentiate between domestic and non-domestic ICP's. The default definition for domestic installation will be that provided by regulation 64 of the Electricity Act 1992. All other connections will be deemed non-domestic.

Regulatory requirement.

15. The differential in ICP charges between rural and urban connection will be maximised within the constraints of regulatory attention regarding rural charges and the 10 % fixed charge regulation for domestic users.

Urban – Rural differentiation is desired from a cost-signalling perspective.

16. Within the constraints of regulation the cross-subsidies between load groups will be minimised.

If supplies were truly uneconomic then their costs would ideally be signalled to encourage shifting to alternative supply arrangements. For low use connections costs already exceed the next lowest cost alternatives with very inelastic demand i.e. cost doesn't matter to these consumers. It may be necessary to differentiate remote rural consumers from rural consumers in order to develop an acceptable justification.

17. The burden of cross-subsidy will be shifted from non-domestic urban users to the other load groups such that a Nil subsidy burden position is targeted.

Non-domestic urban users are the regions wealth creators and their success benefits the whole community. They have the greatest need for a competitive power supply. ENL's shareholder has not indicated a desire for lower domestic tariffs.

18. Fixed charges will be based on capacity and number of phases representing the cost of connection assets.

Fixed charges will reflect user-specific asset costs.

19. Connections will be decommissioned one month after the retailer advises the connection is no longer required and stops paying the fixed charge. Reinstatement will attract the same costs as for a new connection.

Decommissioning of ICP's is a credit control and revenue protection mechanism.

20. New connections will attract a capital contribution fee equivalent to the marginal cost of providing an extra 3kVA for urban connections or at cost for dedicated asset connections e.g. large urban or rural connections.

Traditionally urban consumers have faced minimal connection costs unless asset upgrade is necessary. This results in very harsh and inconsistent costs if one consumer happens to be the "straw that broke the camels back". Also networks carried the cost of upgrades that could not be allocated to a specific new load.

21. **No sub-division rebates or ENL contributions will be made towards establishing new connections. However ENL will allocate its network capacity at its discretion where benefits are shared by multiple customers e.g. zone substation contingency capacity.**

Rebates are a subsidy that does not demonstrate any impact on developers decision to invest.

22. **All services provided beyond the connection point will be charged on a user-pays-basis e.g. service line maintenance, tree trimming, etc.**

Services beyond the connection point are user specific and non-regulated revenue.

23. **Substantial repairs and upgrades in excess of annual revenue to uneconomic spur lines will be levied across users of that spur on a user pays basis.**

The company has no obligation or support for making uneconomic investments. Our legal right to make such levies has been confirmed.

24. ENL will promote disconnection or service reduction of uneconomic supplies even though while connected these supplies make a small contribution towards costs. Long-term reduction in uneconomic asset is the predominant objective.

Elimination of uneconomic supplies is hastened by not maintaining low hurdles to remaining connected. Ending our obligation to supply can only be achieved by removing connections.