Electricity
Asset Management Plan
2011 – 2021

Executive Summary

[Disclosure AMP]

Summary of the Asset Management Plan

Vector aims to be:

"New Zealanders' first choice for integrated infrastructure solutions that build a better, brighter future"




This Asset Management Plan supports achieving our vision.

Purpose of the Plan

The purpose of this Asset Management Plan (AMP) is to comply with requirement 7 of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008. It covers a ten year planning period from 1 April 2011 to 31 March 2021.

The AMP is consistent with Vector's internal plans and accurately represents asset management practices at Vector as well as the forecasted ten year capital and maintenance expenditure on the Vector electricity network[1]. The objectives of the AMP are to:

- Inform stakeholders about how Vector intends to manage its electricity distribution network based on information available at preparation;
- Demonstrate alignment between electricity network asset management and Vector's vision and goals;
- Provide visibility of effective asset management at Vector;
- Provide visibility of forecast electricity network investment programmes and forecast medium-term construction activities to external users of the AMP;
- Demonstrate innovation and efficiency improvements;
- Discuss the impact of regulatory settings on future investment decisions;

[1] After allowing for the difference between Vector's financial year (Jul-Jun) and the regulatory financial year (Apr – Mar).

- Discuss expected technology and consumer developments and the asset investment strategies to deal with a changing environment; and
- Meet Vector's regulatory obligations under the aforementioned information disclosure requirements.

From an asset manager perspective the AMP:

- Supports continued improvement in Vector's performance;
- Is essential to our goal to be effective asset managers; and
- Will help the Vector Group achieve its overarching vision.

Economic Outlook

Qualification

This AMP represents Vector's current and best view of the ongoing investment, maintenance and operational requirements of its electricity network, in the current operating environment. However, as discussed below, the business faces significant ongoing uncertainty, especially in relation to the current investment landscape and the still-developing regulatory environment. This has a direct impact on Vector's ability to make investment decisions and attract investment capital.

Vector follows an annual budget process and the implementation of the works programmes may be modified to reflect any changing operational and economic conditions as they exist or are foreseen at the time of finalising the budget, or to accommodate changes in regulatory or customer requirements that may occur from time to time. Any expenditure must be approved through normal internal governance procedures. This AMP does therefore not commit Vector to any of the individual projects or initiatives or the defined timelines described in the plan.

Economic factors

At the time of preparing the previous two AMPs (between April 2008 and March 2010) New Zealand was entering into and emerging from a major economic downturn. This downturn initially did not result in the anticipated electricity demand or connection slowdown. With signs of recovery starting to surface towards the second half of 2009 it was anticipated demand and energy delivery would start to grow. However, based on our recent experience (unaudited), the 2010 maximum electricity demand appears to be somewhat weaker than in 2009. This could be a short-term aberration rather than indicative of ongoing economic pressure, but recent press reports indicate the economic recovery appears to have stalled (with GDP growth for the second and third quarter of 2010 at 0.1% and -0.2% respectively).

At the time of preparing this AMP, Christchurch experienced a major earthquake. This is anticipated to have an impact on the New Zealand economy, but at this stage it is not yet clear how that would affect the Auckland region. The situation is being reviewed and will be reflected in future plans.[2]

For the purposes of this AMP, Vector has assumed that economic growth will resume at relatively modest levels in the short to medium term.

The Government launched an infrastructure programme that brought forward a number of construction projects. This requires some major network projects (for

---

[2] Post the Christchurch event, Vector has also started on a full review of its earthquake-related asset management standards and practices. Where appropriate these will be adapted to reflect new learning. Our response plans and network resiliency to other natural disasters (such as volcanoes) will be reviewed at the same time.

example, to supply electricity to the Waterview tunnel and the Victoria viaduct tunnel) and gave rise to substantial services relocation projects.

After a long period of relative stability, electricity distribution and consumer technologies are now undergoing accelerated change. New applications, associated with intelligent networks and consumer technology, are arising that could have a substantial impact on how networks develop in the medium to longer term, and hence also on the associated expenditure patterns.

Regulatory factors

The requirement for the Commission to set Input Methodologies was introduced in the 2008 amendments to the Commerce Act. The amendments were intended to address concerns with regulatory instability and uncertainty and emphasised the importance of the Commission ensuring electricity distribution businesses have both regulatory certainty and incentives to invest. While a number of issues have been clarified through the development process, Vector does not yet believe that the Input Methodologies for Electricity Distribution Services, finalised in December 2010, provide an adequate level of certainty or investment incentives. In addition, the assessment of the P_0 adjustment will not be finalised until late 2011 and the methodology by which this will be implemented remains highly uncertain. This creates significant uncertainty for electricity distribution businesses and impacts on their ability to invest.

Vector also considers that the Input Methodologies decision on the Weighted Average Cost of Capital (WACC) set returns below commercially realistic levels, creating difficulties for electricity distribution businesses as they attempt to make investment decisions and attract investment capital.

It is not clear whether future regulatory incentives and/or customer expectations will support investment in reliability improvements. While the Commerce Act (Section 54Q) requires the promotion of energy efficiency, and the Commission has indicated it will consult on regulatory mechanisms to incentivise quality of supply improvements or ways of improving energy efficiency in the future, it has to date given no assurances that such incentives will be implemented. To date, discussion of these factors has been missing from the Commerce Commission's Input Methodologies development process. In the absence of such quality or efficiency incentives, investment may only meet the current regulatory requirement to maintain network performance and quality of supply at its historical levels.

A key element of the regulatory regime is the basis of establishing the value of the regulatory asset base (RAB). The Commission, in the Input Methodology Determination, decided that the 2004 Optimised Deprival Valuation (ODV), with some adjustments and indexed forward at CPI, will be used as the opening RAB instead of a new asset valuation using labour and material cost data that reflects the competitive market price for electricity distribution at the start of the new regulatory regime (2010). Vector believes this represents a fundamental change in the Commission's approach and that the regulatory uncertainty this brings about will have a significant dampening effect on the willingness and ability of electricity distribution businesses to invest.

Technical factors

Vector anticipates that the Auckland region will experience continued population increase and associated growth in electricity demand for the foreseeable future.

This will inevitably involve strengthening the existing electricity distribution network through conventional means, but will also employ emerging technology and alternative energy sources to enhance utilisation of existing network assets and defer investments where feasible to do so. Underlying all of this, Vector will continue to ensure a safe and reliable electricity supply, meeting our customers' electricity demand requirements.

Improvements in the AMP and Asset Management at Vector

Vector noted the results of the Commerce Commission review of the 2009 AMP. Vector's 2010 AMP has already been thoroughly revised to reflect the Commission's feedback. This (2011) AMP builds on the 2010 document and incorporates further developments in Vector's approach to and thinking on asset management.

Vector has, over an extended period, engaged external expert technical advisers on an annual basis to review its asset management practices. While these reviews have been very positive in their feedback – confirming asset management at Vector conforms to industry best-practice – we have taken note of the feedback and recommendations received, and where practical and beneficial, reflected this in our asset management practices.

Important further changes recorded in this AMP include:

- The investment plan for network development has been expanded, based on changing electricity demand patterns, updated customer requirements and reflecting the impact of Vector's ongoing capex efficiency improvements. It also reflects in more detail the project options considered;
- The renewal investment plan reflect increased availability of historical performance information, continuing improvement in our understanding of asset performance and more detailed justification of investments;
- The AMP includes an updated reflection of Vector's ongoing research into the impact and opportunities of changing network and customer technology and deployment strategies;
- Load forecasting and security of supply methodologies have been further developed and are described in more detail, reflecting these developments; and
- The description of the explicit link between asset investment and achieving Vector's overarching strategy and goals is further developed.

Vector's Network

Vector's supply area covers most of the area administered by the newly formed Auckland Council as shown in the map below. Vector operates an electrically contiguous network[3] from Papakura in the south to Rodney in the north. While Vector operates this as a single network, for legacy reasons, it is convenient to describe a Southern region and a Northern region to reflect the different characteristics of the networks.

The Northern region covers those areas administered by the previous North Shore City Council, the Waitakere City Council and the Rodney District Council, and consists of residential and commercial areas in the southern urban areas, light industrial and commercial developments around the Albany Basin, and residential and farming communities in the northern rural areas.

The Southern region covers areas administered by the previous Auckland City Council, the Manukau City Council and the Papakura District Council, and consists of residential and commercial developments around the urban areas on the isthmus, concentrated commercial developments in the Auckland central business district (CBD), industrial

[3] In addition to the electricity network in Auckland, Vector also owns an 11kV network to supply the Fonterra cheese factory at Lichfield.

developments around Rosebank, Penrose and Wiri areas, and rural residential and farming communities in the eastern rural areas.

In addition, Vector supplies a large customer at Lichfield which is a stand-alone supply.

Network Summary (Year ending 31 March 2010)

Description	Quantity
Consumer connections	527,096
Network maximum demand (MW)*	1,775
Energy injected (GWh)*	8,681
Lines and cables (km)**	17,631
Zone substations***	104
Distribution transformers	20,862

* Includes embedded generation exports

** Energised circuit length

*** Figure includes Lichfield but excludes Auckland Hospital and Highbrook

Demand Forecasts

Demand growth remains a key investment driver for the electricity distribution network. As noted before, Vector is observing short-term fluctuations in annual peak demand. However, the underlying factors supporting long-term growth remain in place and in the longer term a continued increase in maximum electricity demand is anticipated.

Vector has been monitoring developments of various technologies that could impact on the demand and demand characteristics on the network and this has been incorporated in our demand forecasts (with various scenarios analysed).

As in previous years, the demand forecast takes into account any existing and known new distributed generation, reactive compensation development and demand management policies.

The winter and summer demand forecasts are detailed at zone substation level in Section 5.4. The maximum network demand and energy consumption for the 2009/10 (regulatory year) is given below.

	Peak Demand* (MW)	Total Energy Injected (GWh)
From grid exit points	1,590	8,576
From embedded generation**	185	106
Total	1,775	8,681

* Coincident demand

** Embedded generation includes Southdown

Network Development

Planning Criteria

Vector's approach to network development planning is driven by:

- Ensuring the safety of the public, our staff and our service providers;
- Meeting network capacity and security requirements;
- Customer needs, which vary by customer segment and are reflected by service level standards;
- Striving for least life-cycle cost solutions (optimum asset utilisation) and optimum timing for capex;
- Maximising capex efficiency in a sustainable manner;
- Outcomes that improve asset utilisation taking into account the increased risk trade-off;
- Incorporating enhanced risk management strategies and processes into our planning philosophy;
- Continuously striving for innovation and optimisation in network design, and trialling new technology such as remote switching technology, smart meters at distribution substations, LV/MV monitoring and control technologies to improve network performance;
- Encouraging non network and demand-side solutions where practicable;
- Reference to targets set by industry best practice;
- Ensuring assets are operated within their design (cyclical) rating;
- Meeting statutory requirements such as voltage, power quality (PQ); and
- Providing different levels of service to different customer segments, reflecting as far as practicable their desired price/quality trade-off.

Vector's planning criteria are detailed in Section 5 of this AMP.

Network Development Plan

Vector's ten-year network development plan is described in Section 5 of the AMP.

This plan details the anticipated electricity demand in the various parts of the Auckland region for the next ten years. Based on these demand forecasts and our network planning criteria, various projects are planned (and alternatives considered) to ensure that adequate supply capacity and reliability levels will be maintained. Planning is especially detailed for the first five years of the plan.

Service Commitment

Vector operates two forms of supply contracts with its customers. In the Southern region, Vector contracts directly with the end users for line services. In the Northern region Vector contracts with energy retailers for line services, while end users contract with energy retailers for both energy and line services (interpose arrangement).

In the Southern region, Vector promotes its service commitment through the "Vector promise" under which Vector provides its customers a prescribed supply quality and service standard, or a level of compensation where this is not achieved. The level of service delivered to customers depends on the location of the customer. Homes in the city or urban areas generally have better reliability than those in rural areas. This is mainly due to the extensive use of overhead networks in rural areas, and the associated length and exposure to the environment of these. While urban networks are not immune, rural networks are more prone to interference from factors that are largely outside Vector's control, such as severe weather conditions, bird strikes, car versus pole accidents and other environmental factors. (Note that incidents arising as a result of bulk supply failures – generation or transmission – or of extreme events are excluded from this scheme).

A similar "Charter payment" arrangement operates in the Northern region under which Vector provides the end users a prescribed supply quality through the retailers, with a level of compensation (channelled through the retailer) where this is not achieved.

During 2009 Vector concluded outage management agreements with most retailers, to improve customer experience in reporting problems and improve response times. Vector's customers are now put in direct contact with Vector's own response staff should an outage be the result of a distribution network problem.

Vector's supply quality and service standards are explained in detail in Section 4 of this AMP.

Asset Management Planning

Maintenance Planning Policies and Criteria

Vector's overall philosophy on maintaining network assets is based on four key factors:

- Ensuring the safety of consumers, the public and the network field staff;
- Ensuring reliable and sustainable network operation, in a cost-efficient manner;
- Achieving the optimal trade off between maintenance and replacement costs. That is, replacing assets only when it becomes more expensive to keep them in service. Vector has adopted, where practicable, condition-based assessments rather than age based replacement programmes; and
- Integration (alignment) of asset management practices given we are a multi utility asset manager.

Vector has developed maintenance standards for each major class of asset it owns. These detail the required inspection, condition monitoring and maintenance tasks, and the frequency at which these are required. The goal of these standards is to ensure that assets can operate safely and efficiently to their rated capacity for at least their full normal lives. Data and information needs for maintenance purposes are also specified.

Based on these maintenance standards, to ensure that all assets are appropriately inspected and maintained, Vector's maintenance contractors develop an annual maintenance schedule for each class of asset they are responsible for. The asset maintenance schedules are aggregated to form the overall annual maintenance plan which is implemented once it has been signed off by Vector. Progress against the plan is monitored monthly.

Defects identified during the inspections are recorded in the contractor's defect database with a copy being kept by Vector. Contractors prioritise the defects for remedial work based on risk and safety criteria. Work necessary in less than three months is undertaken immediately as corrective maintenance. Work that can be carried out over a three to twelve month period is included in the corrective maintenance or asset replacement programme. Work not required within 12 months is generally held over for the future.

Root cause analysis is normally undertaken as a result of faulted equipment. This is also supplemented by fault trend analysis. If performance issues with a particular type of asset are identified, and if the risk exposure warrants it, a project will be developed to carry out the appropriate remedial actions. The asset and maintenance standards are also adapted based on learning from such root cause analysis.

The following summarises the different types of maintenance programmes for the electricity network assets:

- Preventative maintenance:
  - Asset inspections as per asset management standards;
  - Condition testing as specified in asset management standards; and
  - Inspection and test intervals based on industry best practice and Vector experience.
- Corrective maintenance:
  - Correction of defects identified through preventative maintenance.
- Reactive maintenance:
  - Correction of asset defects caused by external influences, or asset failure.
- Value added maintenance:
  - Asset protection (e.g. cable location and marking, stand-overs).
- Vegetation maintenance:
  - Preventing interference or damage to assets (e.g. tree-trimming).
- Non-core maintenance:
  - Non-standard assets (e.g. tunnels) and maintaining spares.

Asset renewal planning

Vector's asset renewal plans are discussed in Section 6. The overall asset-condition of various asset categories is discussed in detail, highlighting areas where upgrades or renewal is required (as well as the process and factors support these decisions). This forms the basis of the ten-year asset renewal programme.

In general Vector replaces assets on a condition-assessment rather than age-basis. We strive to achieve the optimal replacement point where the risk associated with asset failure and the likelihood of this occurring becomes unacceptably high, and it is more economically efficient to replace an asset than to continue to maintain it.

Risk Management

Risk Management Policies

Managing risk is one of Vector's highest priorities. Risk management is practiced at all levels of the organisation and is overseen by the Board Risk and Assurance Committee and the Executive Risk and Assurance Committee.

Vector's risk management policy is designed to ensure that material risks to the business are identified, understood, and reported and that controls to avoid or mitigate the effects of these risks are in place. Detailed contingency plans are also in place to assist Vector in managing high impact events.

The consequences and likelihood of failure or non performance, current controls to manage these, and required actions to reduce risks, are all documented, understood and evaluated as part of the asset management function. Risks associated with the assets or operations of the network are evaluated, prioritised and dealt with as part of the network development, asset maintenance, refurbishment and replacement programmes, and work practices.

Asset-related risks are managed by a combination of:

- Reducing the probability of failure through the capital and maintenance work programme and enhanced work practices, including design standards, equipment specification and selection, quality monitoring, heightened contractor and public awareness of the proximity of or potential impact of interfering with assets; and
- Reducing the impact of failure through the application of appropriate network security standards and network architecture, selected use of automation, robust contingency planning and performance management of field responses.

The capital and maintenance asset risk management strategies are outlined in the Asset Maintenance and Network Development sections (Section 6 and Section 5). Vector's contingency and emergency planning is based around procedures for restoring power in the event of a fault on the network, and is detailed in Section 5 of this AMP.

Vector also recognises that information technology (IT) systems are a very important part of its business and asset management framework. Vector operates advanced real-time network control and protection systems, deeply integrated with the IT systems of the rest of the business. Potential compromise of the (cyber) security of our IT systems, including our real-time control systems, is recognised as a major (and increasing) business and network risk. Over the past year Vector has implemented several enhancements to its cyber-security systems to manage this risk and create a more robust operating environment. Further security enhancements will be implemented on an ongoing basis.

Health and Safety

At Vector, safety is a fundamental value, not merely a priority. We are committed to a goal of zero harm to people, assets and the environment. Vector's Health and Safety Policies can be found in Section 8 of this AMP. In summary, the policies are developed to ensure safety and wellbeing of its staff, contractors and the public at its work sites and around its assets.

To achieve this Vector aims to comply with all relevant health and safety legislation, standards and codes of practices; establish procedures to ensure its safety policies are followed; encourage its staff and service providers to participate in activities that will improve their health, safety and wellbeing; and take all practical steps to ensure its field services providers (FSPs) adhere to Vector's health and safety policies and procedures. Vector's health and safety practice can be found in Section 8 of this AMP.

Environment

Vector's environmental policy is contained in Section 8 of this AMP. In summary, the policy is developed to monitor and improve Vector's environmental performance and to take preventive action to avoid adverse environmental effects of our operation.

To achieve this Vector will:

- Plan to avoid, remedy or mitigate adverse environment effects of our operations; and
- Focus on responsible energy management and energy efficiency for all our premises, plant and equipment where it is cost effective to do so.

Vector's long term operational objectives with regard to environmental factors are to:

- Utilise fuel as efficiently as practicable;

- Mitigate, where economically feasible, fugitive emissions and in particular greenhouse gas emissions;
- Wherever practicable use ambient and renewable energy; and
- Work with consumers to maximise energy efficiency.

Approval of the AMP and Reporting on Progress

Approval of the disclosure AMP is sought once a year, at the March Vector board meeting. This timing is aligned with the regulatory requirement to publish a disclosure AMP at the end of March each year. No update of the AMP is made between publication dates[4].

As noted above, the content of this AMP is consistent with Vector's internal asset management business plans, which are core to the electricity distribution business. Progress in implementing Vector's internal asset management business plans is regularly monitored, and the plans are updated on a regular basis to reflect a changing environment[5].

Vector measures progress against its investment plans and asset performance through several metrics, including:

- Monthly reporting on progress and expenditure on major projects/programmes;
- Reliability performance – SAIDI, SAIFI, CAIDI (network wide, as well as on a per feeder or zone substation basis);
- Performance and utilisation of key assets such as sub-transmission cables, distribution feeders, power transformers, etc.;
- Progress with risk register actions;
- Health, safety and environmental issues; and
- Security of supply.

Financial Forecasts

The following table summarises the capital and operations & maintenance expenditure forecast covering the AMP planning period.

[4] By contrast, the internal asset management documents are kept up to date on a more regular basis.

[5] Material changes, with potential major budget, risk or reliability consequences, are reported to the Board.

10 Year Forecast of Expenditures	Mar 10 Actual	Mar 11 Budget	Mar 12 Forecast	Mar 13 Forecast	Mar 14 Forecast	Mar 15 Forecast	Mar 16 Forecast	Mar 17 Forecast	Mar 18 Forecast	Mar 19 Forecast	Mar 20 Forecast	Mar 21 Forecast
Customer connection	16.8	17.5	21.6	22.0	22.2	22.4	22.5	22.6	22.6	22.6	22.6	22.6
System growth	31.7	43.3	55.5	50.6	45.0	41.0	43.1	42.2	39.4	46.4	44.9	41.0
Asset replacement and renewal	42.5	47.5	55.9	63.2	62.7	59.5	59.8	55.2	56.1	55.2	56.5	54.9
Reliability, safety & environmental	1.7	4.5	3.4	4.0	3.8	3.2	2.8	2.8	2.8	2.8	2.8	2.8
Asset relocation (including undergrounding)	21.3	23.3	25.8	21.6	19.4	19.1	18.5	18.3	18.3	18.3	18.3	18.3
Capital Expenditure Subtotal	114.0	136.1	162.2	161.3	153.1	145.1	146.7	141.1	139.2	145.3	145.1	139.6
Routine & preventive maintenance	14.3	13.7	19.6	19.8	19.7	19.9	19.9	20.0	20.0	20.1	20.2	20.3
Refurbishment & renewal	10.8	11.8	11.6	12.0	11.9	11.9	11.0	10.7	10.7	10.8	10.7	10.7
Fault and emergency	15.8	14.9	13.0	13.1	13.1	13.2	13.3	13.3	13.4	13.5	13.6	13.6
O & M Subtotal	41.0	40.4	44.2	44.8	44.8	44.9	44.1	44.0	44.2	44.4	44.5	44.7
Total Direct Expenditure	155.0	176.5	206.4	206.0	197.9	190.1	190.8	185.1	183.4	189.7	189.7	184.3
Overhead to underground	12.5	12.7	17.3	13.4	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

* Figures are in January 2011 dollars (million);

** The year reference indicates the end date of the financial year

Glossary of Terms

A	Ampere
AAC	All aluminium conductor
AAAC	All aluminium alloy conductor
ABS	Air break switch
ac	Alternating current
ACSR	Aluminium conductor steel reinforced
ADMD	After diversity maximum demand
AELG	Auckland Engineering Lifelines Group
AMP	Asset management plan
AUFLS	Automatic under frequency load shedding
AI	Asset Investment, a functional unit at Vector
BRAC	Board risk and assurance committee
Capex	Capital expenditure
CATI	Computer assisted telephone interviewing
CAU	Census Area Unit
CB	Circuit breaker
CBD	Central business district
CDEM	Civil Defence Emergency Management
CIM	Common information model, as defined by IEC 61970-301
CMS	Customer Management System
CPI	Consumer price index
Cu	Copper
dc	Direct current
DFA	Delegated financial authority
DGA	Dissolved gas analysis
DP	Degree of polymerisation
EGCC	Electricity and Gas Complaints Commission
ERAC	Executive risk and assurance committee
EV	Electric Vehicle
FAR	Fixed asset register
FF cables	Fluid filled cables
FSP	Field service provider
GIS	Geospatial Information System
GXP	A facility owned by Transpower that directly connects the Vector network to the national grid. A GXP may contain more than one supply bus (of same or different voltages).
HV	High voltage – ac rated voltages above 52kV (IEC62271)
HVABC	High voltage aerial bundle cable
IEC	International Electrotechnical Commission
IED	Intelligent electronic data and/or devices
IP	Internet protocol
km	Kilometre
KPI	Key performance indicators
kV	Kilovolt
kVA	Kilovolt ampere
kVAr	Kilovolt ampere reactive
kW	Kilowatt

LV	Low voltage – ac rated voltages below 1kV
LVABC	Low voltage aerial bundle cable
LTOS	Live tank oil sampling
MCR	Maximum continuous rating
MGCU	Mobile generator connection unit
MIS	Maintenance Information System
MUSA	Multi utility service agreement
MV	Medium voltage – ac rated voltages above 1kV up to and including 52kV
MVA	Mega volt ampere
MVAr	Mega volt ampere reactive
MW	Megawatt
NER	Neutral Earthing Resistor
OCB	Oil type circuit breakers
ODV	Optimised deprival value/valuation
Opex	Operational expenditure
PD	Partial discharge test
PI	Plant information system
PIAS	Paper insulated aluminium sheath
PILC	Paper insulated lead cable
PQ	Power quality
PQM	Power quality monitor
PV	Photo-voltaic
RAB	Regulatory asset base
RTU	Remote terminal unit
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAP	Systems Applications and Processes (Vector's corporate enterprise resource planning system)
SAP-BW	SAP Business Warehouse
SAP-FI	SAP Financial Information
SAP-GIS	SAP Geospatial Information System
SAP-MM	SAP Materials Management
SAP-PM	SAP Plant Maintenance module
SCADA	Supervisory Control and Data Acquisition system
SD	Service Delivery, a functional unit at Vector
SF_6	Sulphur hexafluoride
SF_6GIS	HV switchgear using Sulphur hexafluoride as the insulation and breaking medium
SLA	Service level agreement
SWA	Steel wire armour
TAM	Technical asset master
TASA	Tap changer activity signature analysis
TC	Technical Council
TCA	Transformer condition assessment
THD	Total harmonic distortion
TUDS	Total Underground Distribution System
V	Volt
VCB	Vacuum circuit breaker
VRLA	Valve regulated lead acid

Substation	A network facility containing a transformer for the purpose of transforming electricity from one voltage to another. A substation may contain switchboards for dispatch or marshalling purpose. A substation may also contain more than one building or structure on the same facility.
Switching station	A facility containing one or more switchboards (or switches) for the purpose of rearranging network configuration or marshalling the network through switching operation.
Zone substation	A substation for transforming electricity from sub-transmission voltage (110kV, 33kV or 22kV) to distribution voltage (22kV or 11kV).
Distribution voltage	A substation for transforming electricity from distribution voltage (22kV or 11kV) to 400V distribution voltage.
Bulk supply substation	A substation owned by Vector that directly connects the Vector network to the national grid. A bulk supply substation may contain more than one supply bus (of same or different voltages).
National grid (or grid)	The 110kV and/or 220kV AC network and the DC link between the North Island and the South Island owned by Transpower for connecting electricity generation stations to grid exit points.

Electricity
Asset Management Plan
2011 – 2021

Table of Contents

(Note that each section is individually numbered)

Glossary of terms

Executive Summary

Section 1

Section 2

Section 3

Section 4

Section 5

Section 6

Section 7

Section 8

Section 9

Electricity
Asset Management Plan
2011 – 2021

Background and Objectives – Section 1

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

1. Background and Objectives

1.1 Context for Asset Management at Vector

Asset management is critical for ensuring Vector's electricity distribution business provides safe and reliable services which meet the needs and expectations of consumers, help to achieve the business' commercial and strategic objectives and satisfies its regulatory obligations. Effective planning helps ensure Vector maintains and invests appropriately in its network. Vector's ongoing goal is to achieve a high standard of asset management, given its critical nature to the business and consumers, while reflecting the regulatory and economic environment within which it finds itself.

The asset management framework adopted for Vector's electricity distribution business is illustrated in Figure 1-1.

This is a generic asset management model widely adopted by many types of infrastructure businesses. The framework is superimposed on the environment within which Vector operates.

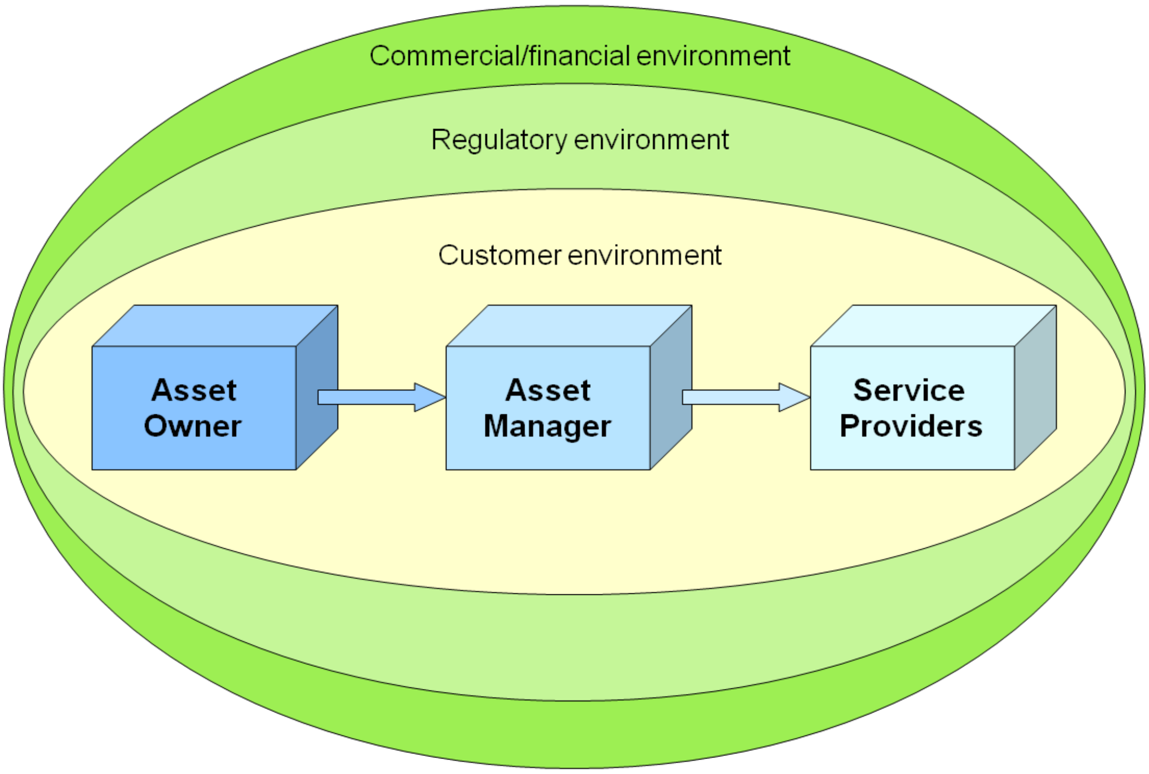


Figure 1-1 : Vector's asset management framework

In this model, the Asset Owner is the highest level of management within the organisation that owns the assets. In Vector's case this is the Vector executive, with oversight from the Vector Board. The Asset Owner determines the operating context for the Asset Manager, focusing on corporate governance and goals, and the relationship with regulators and other stakeholders.

The Asset Manager develops the asset management strategy, directs asset risk management, asset investment and asset maintenance planning, and decides where and how asset investment is made. The Asset Manager sets policies, standards and procedures for the service providers to carry out. In Vector the Asset Manager function is, broadly, the responsibility of the Asset Investment (AI) group.

The Service Providers are responsible for delivering asset investment programmes, to maintain and operate the assets based on the guidelines set by the Asset Manager.

In Vector the Service Providers are a combination of the Service Delivery (SD) group - capital programmes, network operations and service operations - and the external contractors and consultants supporting them (see Section 1.7 for a discussion).

Asset management is strongly influenced by customer needs as well as commercial, financial and regulatory demands and strategies:

- Customer needs and expectations, along with safety and technical regulations, form the very basis that determines the make-up of electricity networks. Network layout and capacity is designed to ensure contracted or reasonably anticipated customer demand can be met during all normal operating circumstances. Quality of supply levels, which relate to the level of redundancy built into a network to avoid or minimise outages under abnormal operating conditions, are likewise based on customer requirements and the value they place on reliability of supply.

  Most direct interaction with customers occurs through the Commercial group. Asset management involves close interaction with the Commercial group to assist with understanding and addressing customer technical requirements, consumption forecasts and upcoming developments.

- The economic regulatory environment can be seen as a proxy for the market in which we operate (this refers to economic regulation under Part 4 of the Commerce Act). In addition, there are also technical regulations around how networks are allowed to be built and operated. Not only does regulation influence technical network parameters such as the extent of assets installed and the levels of spare capacity in the assets themselves,[1] but it also limits the commercial returns on investments and hence directly influences investment decisions. There are also a number of regulatory compliance rules that have an impact on network configuration and operations.

  Regulatory certainty is critical to the investment framework, given the long-term nature of the assets and the need for electricity distribution businesses to have confidence that they can expect to recover their cost of capital (i.e. earn a sustainable commercial return) from efficient and prudent investment. Importantly, we also have to attract capital both locally and from offshore.[2]

  Direct contact with the regulators is generally maintained through the Regulation and Pricing group, which in turn works with the Asset Manager to provide guidance on regulatory issues and requirements. Setting and executing regulatory strategy is also closely intertwined with asset investment activities.

- Vector operates in a commercial environment where shareholders expect a commercially appropriate return on their investments reflecting the risk of the investment. To maintain commercially sustainable returns, Vector has to ensure it is able to make optimal investment and maintenance in the network, including replacement, upgrades and new assets. This requires demonstration that

---

[1] Through setting the optimisation guidelines that apply during valuation of the regulatory asset base.

[2] In Vector's experience, the New Zealand regulatory regime is often cited by capital markets and rating agencies as being uncertain.

investment decisions are not only economically efficient[3], but that realistic alternative options have been investigated to ensure the most beneficial solution – technically and commercially – is applied. This may involve taking a view on likely future technical changes in the energy sector.

In addition, financial governance has a direct and significant bearing on asset management. Capital allocation and expenditure approvals are carefully managed in accordance with Vector's governance policies. Short and long-term budgeting processes take into account the balance between network needs, construction resources and available funding – requiring careful project prioritisation.

Asset management, in particular where expenditure is involved, therefore requires close interaction with the Finance and Service Delivery groups.

In the context described above, a Vector internal asset management business plan was developed to define Vector's asset management policies, responsibilities, targets, investment plans and strategies to deal with the future of the electricity network.

While this business plan's emphasis is on electricity network asset management, it is very much a Vector-wide document. It supports the achievement of the vision and goals of the wider company through maximising the efficiency of asset management activities. Rather than being prepared in isolation by and for the electricity business only, the plan is guided by Vector's overall goals, relies extensively on inputs from all areas within Vector, and one of its key functions is to provide visibility on the asset investment strategies and forecasts to the entire company.

1.1.1 The Role of the Disclosure Asset Management Plan

The regulatory disclosure AMP (i.e. this document) is largely drawn from Vector's internal asset management business plan and strategies. However, the AMP, being a publicly disclosed document and being subject to a prescribed contents structure, differs in some instances from the internal documents, namely:

- The internal asset management business plan and strategies form a key platform to capture in depth our asset management thinking, strategies, detailed plans and forecast expenditure build-ups. They are therefore wider in scope, and more detailed than the AMP;
- Information that is commercially or strategically sensitive to our customers or to Vector is not disclosed in the AMP;
- The regulatory timeline requires reporting on a 1 April to 31 March financial year, whereas the Vector financial year is from 1 July to 30 June; and
- Asset management practices or interactions with other parts of the wider business that Vector considers important, but are not required for the regulatory AMP structure, are sometimes omitted.

The internal and disclosed plans are however consistent and the disclosed plan contains sufficient, accurate information to keep Vector's customers and other interested parties well-informed about our asset management practices and our intended development plans, in accordance with the regulatory requirements and Information Disclosure Handbook guidelines.

[3] Either through demonstrating an appropriate economic return, or being required to ensure network sustainability and reliability.

1.1.2 Relationship between Asset Management and Vector's Strategies and Goals

As indicated above, the Asset Owner determines the operating context for the Asset Manager, focusing on corporate governance, strategies and goals, and the relationship between regulatory issues and other stakeholder requirements. The Asset Manager interprets these strategies and goals and translates the strategic intentions into an asset investment strategy which is supported by a series of asset management policies. Technical standards, work practices and equipment specifications support the asset management policies, guiding the capital and operational works programmes.

Performance of the network is monitored against a set of performance indicators that are based on realising customer expectations, meeting regulatory requirements, meeting safety obligations and achieving best-practice network operation.

The diagram in Figure 1-2 illustrates the relationship between corporate strategies and goals with asset management policy framework.

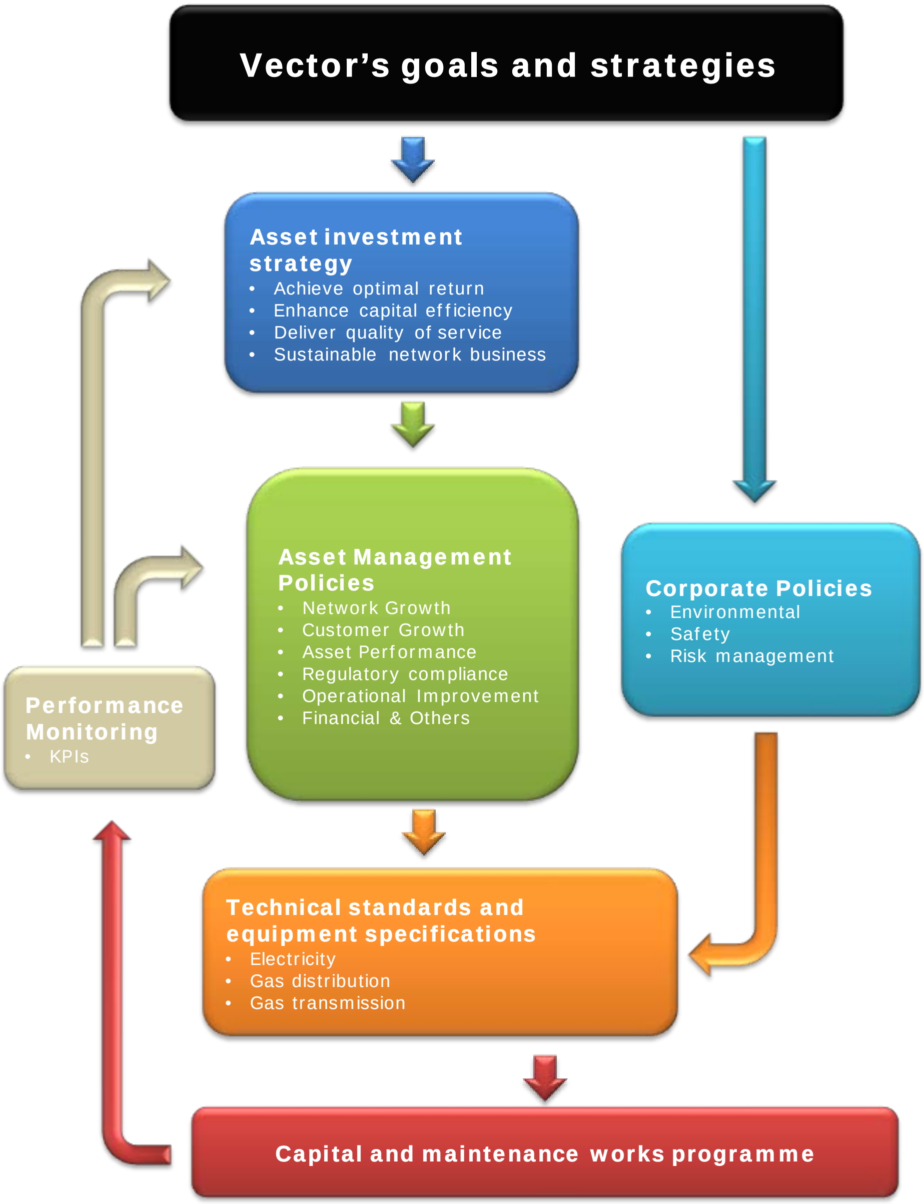


Figure 1-2 : How Vector's asset management strategies and policies relate to the strategic goals

1.2 Planning Period and Approval Date

This AMP covers a ten year planning period, from 1 April 2011 through to 31 March 2021[4] and was approved by the board of directors on 24th March 2011.

The first five years of the plan is based on detailed analysis of customer, network and asset information and hence provides a relatively high degree of accuracy (to the extent reasonably possible) in the descriptions and forecasts. The latter period of the plan is based on progressively less certain information and an accordingly less accurate and detailed level of analysis. From year five on, the AMP is only suitable for provisional planning purposes. In addition to the normal variability around asset performance and customer growth patterns, the accelerating rate of development in technologies such as photovoltaic panels, electric vehicles, smart network and home appliances, batteries and fuel cells is introducing even more uncertainty in the medium to long-term future of network development.

At the time of finalising this AMP, Christchurch experienced a severe earthquake, with a serious impact on utility services. During 2011, Vector will research the impact and implications of this event, culminating in a review of our design and operational standards, to incorporate relevant findings. This may lead to material changes in asset management for the rest of the planning period, to be reflected in future AMPs.

1.3 Purpose of the Plan

This regulatory AMP has been developed as part of requirement 7 of the Commerce Commission's Electricity Distribution Disclosure Requirements 2008 and covers ten years starting on 1 April 2011. The purposes of this AMP are to:

- Inform stakeholders how Vector intends to manage and expand its electricity distribution network based on information available at preparation;
- Ensure the Commerce Commission understands the impact of regulatory settings on future investment decisions;
- Demonstrate alignment between electricity network asset management and Vector's goals and values;
- Demonstrate innovation and efficiency improvements;
- Provide visibility of effective asset management at Vector;
- Provide visibility of forecasted electricity network investment programmes and upcoming medium-term construction programmes to external users of the AMP;
- Discuss Vector's views on expected technology and consumer developments and the asset investment strategies to deal with a changing environment; and
- Meet Vector's regulatory obligation under the aforementioned requirement.

This AMP does not commit Vector to any of the individual projects or initiatives or the defined timelines described in the plan. Vector follows an annual budget process and the implementation of the works programmes may be modified to reflect any changing operational and economic conditions as they exist or are foreseen at the time of finalising the budget, or to accommodate changes in regulatory or customer requirements that may occur from time to time. Any expenditure must be approved through normal internal governance procedures.

---

[4] Vector operates to a June financial year. All asset management and financial reporting is carried out based on its financial calendar. Works programme and the corresponding expenditures presented in this document align with its financial reporting timeframes. To comply with the Commerce Commission's Electricity Information Disclosure Requirements 2004, the budgets and expenditure forecasts in Section 9 are converted into regulatory years (ending on 31 March).

1.3.1 Asset Management in Support of Vector's Vision

Vector's strategic vision is to be:

"New Zealanders' first choice for integrated infrastructure solutions that build a better, brighter future"

To support Vector in achieving this vision a number of group goals have been defined. The group goals are supported by the strategies of the various Vector business units. Asset management, as captured in the internal asset management business plan and also discussed in this AMP, is a key part of the wider AI business plan and consequently plays an important part in achieving the overall Vector vision. The manner in which the AMP supports Vector's vision is demonstrated in Figure 1-3.

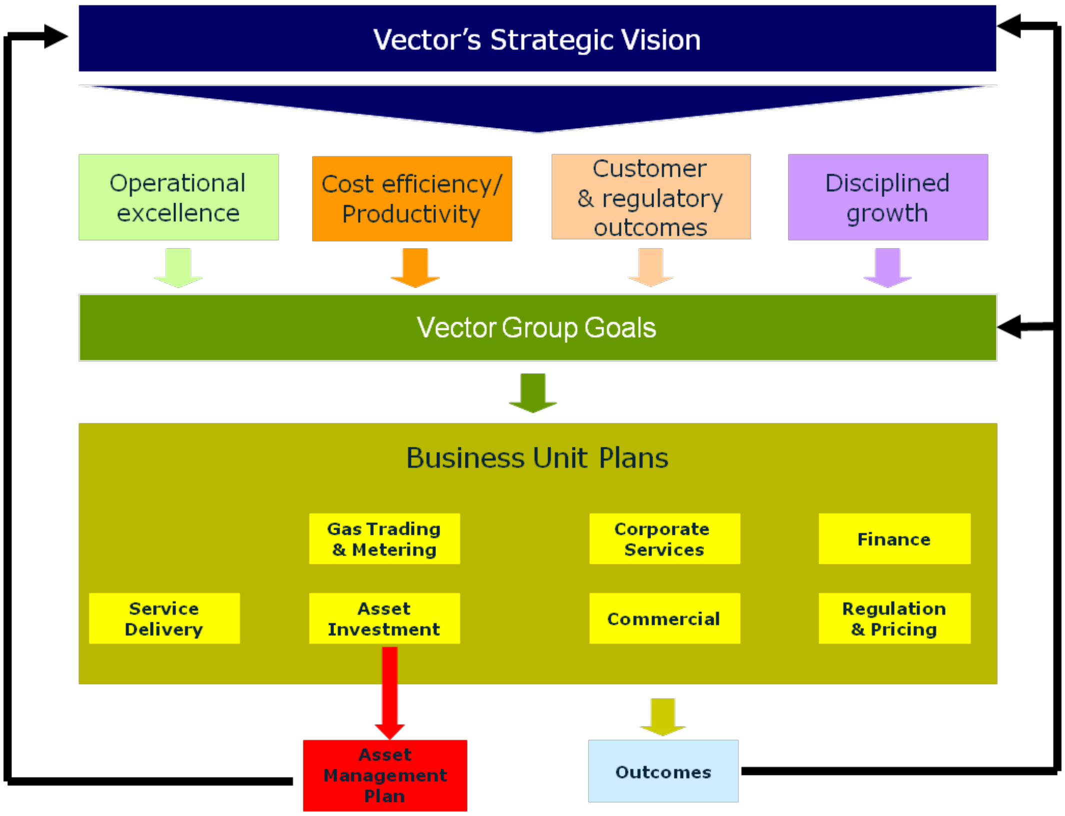


Figure 1-3 : The AMP in support of the overall Vector strategic vision

Table 1-1 below demonstrates how asset management supports Vector to achieve its strategic objectives.

Group Goal	Asset Management in support of
Disciplined Growth	♦ Investigate new technologies and associated opportunities ♦ Optimise financial contributions ♦ Support commercially attractive investments ♦ Innovation and optimal investment efficiency ♦ Economies of scale from long-term view
Customer & Regulatory Outcomes	♦ Technical excellence ♦ Providing reliable service ♦ Fit-for-purpose network designs ♦ Understanding and reflecting customer needs in designs ♦ Security and reliability levels adapted to customer needs ♦ Maintaining appropriate price/quality trade-off ♦ Reliable asset information source ♦ Detailed five-year expenditure budgets ♦ Strategic scenario planning ♦ High quality network planning ♦ Effective maintenance planning
Operational Excellence	♦ Investigate new technologies & opportunities offered ♦ Clear prioritisation standards ♦ Needs clearly defined ♦ Understanding risks ♦ Fit-for-purpose network designs ♦ Providing reliable service ♦ Security and reliability levels adapted to customer needs ♦ Easy-to-maintain and operate networks ♦ Safe networks is top priority ♦ Full compliance with health, safety and environmental regulations ♦ Clear roles and responsibilities for asset management ♦ Strong, well-documented asset management processes ♦ Support sustainability of partners ♦ Clear communication of network standards and designs
People Engagement	♦ Clear roles and responsibilities ♦ Asset management & performance expectations clearly set ♦ Health and safety and risk management principles implemented at an asset investment level

Table 1-1 : How asset management supports Vector's group goals

1.3.2 Vector's Vision Driving Asset Management

In the previous section it was indicated how asset management at Vector supports the group's overall vision and goals. Conversely, and very importantly for this plan, the Vector vision and goals also sets the framework and fundamental parameters for asset management. This is illustrated in Table 1-2.

Group Goal driving	Asset Management
Disciplined Growth	♦ Keep abreast of technology changes ♦ Seek optimal commercial outcomes in investment decisions ♦ Innovation and capital efficiency ♦ Optimised network solutions ♦ Optimised investment timing ♦ Standardisation
Customer and Regulatory Outcomes	♦ Understanding customer needs and recognising this in decisions ♦ Good project communications ♦ Appropriate price/quality trade-off ♦ Soundly justified investment programme ♦ High quality asset data management ♦ Respond to regulatory incentives ♦ Fit-for-purpose solutions ♦ Security of supply levels appropriate to customer needs ♦ Respond to regulatory quality incentives
Operational Excellence	♦ Keep abreast of technology changes ♦ New product development and investment where economically viable ♦ Consistent project prioritisation ♦ High priority projects only ♦ Appropriate to network environment ♦ Maintain appropriate risk levels ♦ Easy-to-maintain and operate networks ♦ Asset decisions reflects safe networks as top priority ♦ Minimising asset environmental impact ♦ Effective consideration of HS&E in investment and maintenance decisions ♦ Clear roles and responsibilities ♦ Strong, well-documented asset management processes ♦ Clear forward view on upcoming work ♦ Consider partner capacity
People Engagement	♦ Setting KPIs for company and individual performance ♦ Technical training & development ♦ Leadership development

Table 1-2 : How Vector's group goals drive asset management

1.3.3 Key Assumptions for the AMP

On a practical level, incorporating the Vector values and goals in the asset management strategy determines the fundamental assumptions or premises on which the AMP is based. These assumptions, listed in Table 1-3 below, reflect the manner in which AI understands and implements Vector's strategic direction.

It should be noted that, following the recent earthquakes experienced in Christchurch and the implications this has highlighted for operating utility services, Vector will be embarking on a review of its network standards during the course of 2011. Modifications to the standards will be adopted as deemed necessary.

KEY PREMISES FOR THE AMP	
The present industry structure remains	The Vector electricity network will continue to operate as a stand-alone, regulated electricity distribution business (not vertically-integrated). Open access of the network will be maintained. The transmission grid will continue to be owned and operated by a separate entity and operated to the good of the larger New Zealand economy. Grid development will continue broadly in its current direction and the existing grid will be maintained in accordance with good industry practice, ensuring that sufficient electricity capacity, at appropriate reliability levels, will be retained to meet the needs of Vector's customers.
Existing Vector electricity business operation model remains	Field services will continue to be outsourced. Adequate resources with the relevant skills will be available to implement the works programme to deliver the service to the required level.
Current supply reliability levels remain unchanged	Under the current regulatory arrangement in New Zealand, there is no clear incentive to improve network reliability from historical levels. However, it is imperative that reliability does not deteriorate. In addition, previous customer survey results indicate Vector's customers in general are satisfied with the quality of service they receive, at the level of price they pay for the service.
Safety will not be compromised	Safety of the public, our staff and our contractors is paramount. Asset management must drive this.
A deteriorating asset base will be avoided	In general, assets will be replaced before they become obsolescent, reach an unacceptable condition, can no longer be maintained or operated, or suffer from poor reliability. (In a number of instances where it is technically and economically optimal and safety is maintained, some assets will be run to failure before being replaced.)
The networks will fully adhere to safety regulations and	Vector fully complies with New Zealand safety codes, prescribed network operating practices and

KEY PREMISES FOR THE AMP	
standard	regulations.
Regulatory requirements will be met	Regulatory requirements with regards to information disclosure or required operating standards will be met accurately and efficiently.
A sustainable, long-term focused network will be maintained	Asset investment levels will be appropriate to support the effective, safe and reliable operation of the network. Expenditure will be incurred at the economically optimum investment stage without unduly compromising supply security, safety and reliability. New assets will be good quality and full life-cycle costing will be considered rather than short-term factors only. Networks will be effectively maintained, adhering to international best-practice asset management principles. Gold-plating or excess assets are not acceptable. Investments must provide an appropriate commercially sustainable return reflecting their risks.
Existing reliability and supply quality levels will generally be maintained	This may change, depending on the Commerce Commission's final interpretation of Section 54Q of the Commerce Act and the regulatory incentives (or disincentives) this brings about.
Under normal operating conditions the full required demand will be met	Assets will not be unduly stressed or used beyond appropriate short or long-term ratings to avoid damage.
Network security standards (for delivery) will be met	In exceptional cases breaches may be accepted, as long as this is consciously accepted, explicitly acknowledged and communicated to affected parties and contingency plans prepared to cater for asset failure. The security standards are based on Vector's best understanding of customer requirements and the price/quality trade-offs they would like to make.
Asset-related risks will be managed to appropriate levels	Network risks will be clearly understood and will be removed or appropriately controlled – and documented as such.
An excessive future "bow-wave" of asset replacement will be avoided	Although asset replacement is not age-predicated, there is a strong correlation between age and condition. To avoid future replacement capacity constraints or rapid performance deterioration, age-profiles will be monitored and appropriate advance actions taken.
Quality of asset data and	Vector's asset management is highly dependent on

KEY PREMISES FOR THE AMP	
information will continue to improve	the quality of asset information. Its information system and data quality improvement programme will continue for the foreseeable future.
More non-network solutions will be adopted	Vector will continue to investigate non-network solutions as practical alternatives to network reinforcements. This includes demand side options, pricing incentives, embedded generation, reactive compensation, alternative fuel, energy storage, etc. Such alternatives will be implemented where it is economical and practical.
New consumer and network technology will progressively influence how the network is operated and utilised	The rate at which new consumer technologies are developing is accelerating. Over the longer-term changing demand and consumption patterns will impact on how the network is managed. This development will offer opportunities for Vector to improve its network and to embrace the future generation of technology. Subject to economic justification, Vector will therefore continue in its evolution of the intelligent electricity network.

Table 1-3 : Key premises for the AMP

These key premises have a direct and major impact on the quality of service provided by the network, the condition of the assets, the levels of risk accepted and the asset expenditure programmes.

1.4 Changing External Outlook

1.4.1 Economic Outlook

The Auckland region is experiencing what appears to be a cautious economic recovery, following the recession of 2008/09. Overall electricity demand in 2010[5] was marginally higher than for 2009, but preliminary figures for winter 2010 show a decline against the previous winter. A slow growth trend is expected to continue in the foreseeable future (see Section 5.3 of the AMP for a discussion).

New residential customer connections, while somewhat down compared with historical rates, have continued at a reasonable pace, reflecting the ongoing population growth in the region[6]. Current projections are that the greater Auckland population will continue to grow by about 2% (22,500) per year for the foreseeable future. Based on historical variability, this equates to between 5,000 and 8,000 new connections (predominantly residential) per year (see Section 5.4 for a discussion).

A number of infrastructure projects accelerated by the government in response to the economic recession are now coming to fruition, most notably the Waterview tunnel construction. These investments are expected to have a material impact on Vector's construction programme over the next three to four years.

In the short to medium-term it is expected that demand growth will continue to be largely driven by steadily increasing numbers of residential and commercial

[5] Disclosure year ending March 2010

[6] Conversely, growth in the commercial/industrial market accelerated from last year.

connections to the network, with industrial load added on a more incremental basis. The potential effect of the Christchurch earthquake has not been incorporated in this evaluation, and some modification to demand growth rates may occur as a result of the economic impact of the event, and/or changing migration patterns. This will be reflected in future AMPs.

1.4.2 Formation of the Auckland Council

From 1 November 2010, the eight district, city and regional councils of Auckland were amalgamated into a single council structure under the Auckland Council. The Auckland Council comprises a single Governance body, seven Council-Controlled Organisations (CCO) and 21 Local boards. Key structural changes include the establishment of CCO's to manage the transport and water service needs for the region. The diagram in Figure 1-4 shows the structure of the Auckland Council.

Figure 1-4 : Structure of the Auckland Council

The changes have a significant impact on Vector's activities in the region. A number of key relationships with regional councils have changed as the management of our existing activities across the region was transferred to new entities and new roles. As the consolidation of the new council structure is still ongoing, it is likely there will be further changes in future that may materially influence Vector's business. Relationships with the new council are constructively and pro-actively managed.

1.5 Asset Management in the Wider Vector Context – Internal Stakeholders

Asset management at Vector is not practised in isolation. It is heavily reliant on inputs from the various parts of the company, either directly or indirectly. The internal asset management business plan also provides visibility of asset management activities to the rest of the company, for incorporation into the broader business plans and strategies. This two-way support flow is illustrated in Figure 1-5 and Figure 1-6.

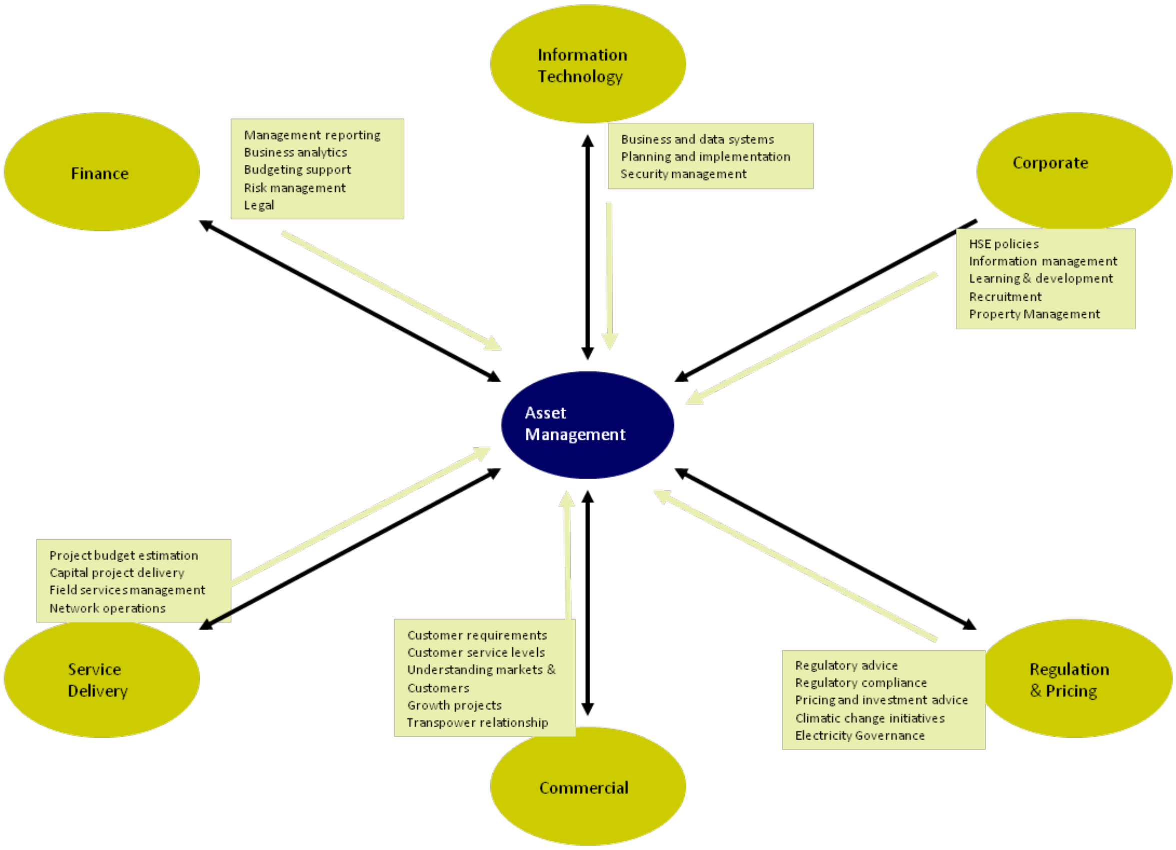


Figure 1-5 : Interaction with the rest of Vector - the flow into asset management

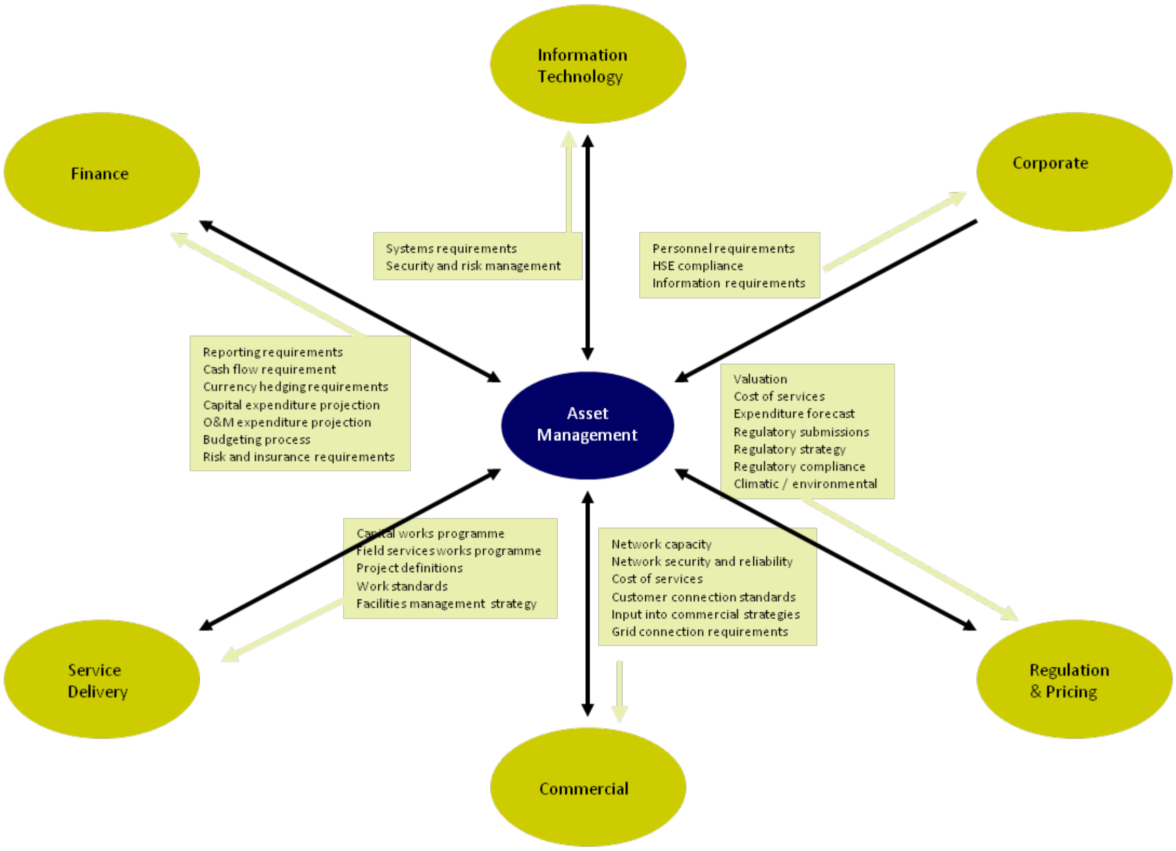


Figure 1-6 : Interaction with the rest of Vector - the flow from asset management

1.6 Asset Management in the Wider Vector Context – External Stakeholders

Vector has a large number of internal and external stakeholders that have an active interest in how the assets of the company are managed. The essential service nature of the service we provide and its importance to the Auckland well-being and economy, gives rise to some stakeholders with a keen interest in how we conduct our business.

In Figure 1-7, the important external stakeholders in Vector are highlighted. Understanding of how these stakeholders interact with Vector and the requirements or expectations they have of the company has a major bearing on the manner in which we construct and operate the electricity networks.

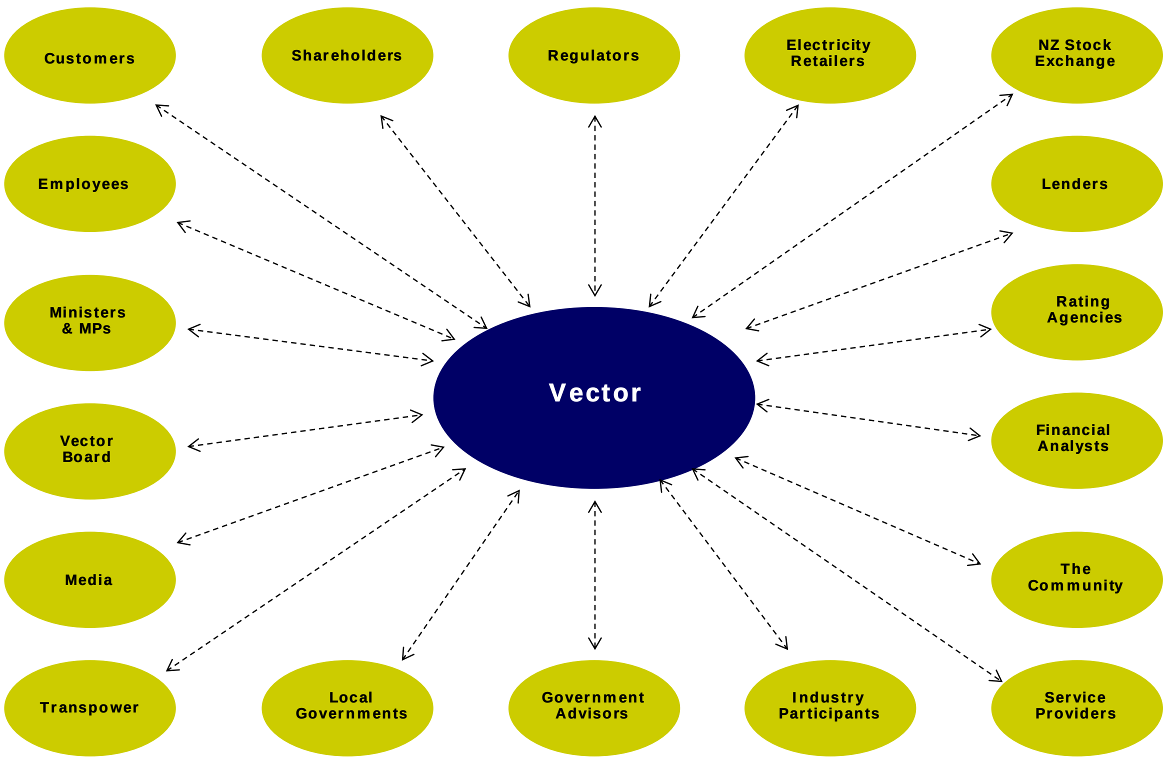


Figure 1-7 : Vector's key external stakeholders

1.6.1 Stakeholder Expectations

Important stakeholder expectations are listed in Table 1-4 below.

Customers (and end-use consumers)	
Reliable supply of electricity	Information in fault situations
Quality of supply	Planned outages
Security of supply	Timely response to complaints and queries
Efficiency of operations	Health and safety
Reasonable price	Environment
Timely response to outages	Timely connections
Innovation, solution-focus	

Shareholders	
Return on investment Sustainable growth Sustainable dividend growth Reliability Confidence in board and management Accurate forecasts	Regulatory and legal compliance Prudent risk management Good reputation Good governance Clear strategic direction
Retailers	
Reliability of supply Quality of supply Managing customer issues	Information in fault situations Ease of doing business Good systems and processes
Regulators	
Statutory requirements Accurate and timely information	Inputs on specific regulatory issues Fair and efficient behaviour
Vector Board	
Return on investment Regulatory and legal compliance Good governance Accurate and timely provision of information Expenditure efficiency	Prudent risk management Reliability of supply Health, safety and the environment Accurate budgeting
New Zealand Stock Exchange	
Compliance with market rules	Good governance
Financial Analysts/Rating Agencies/Lenders	
Transparency of operations Accurate performance information Clear strategic direction Adhering to New Zealand Stock Exchange rules	Prudent risk management Good governance Accurate forecasts Confidence in board and management
Service Providers	
Safety of the work place Stable work volumes Quality work standards Maintenance standards Clear forward view on workload	Construction standards Innovation Consistent contracts Clearly defined processes Good working relationships
Government Advisors	
Accurate and timely provision of information Vector's views on specific policy issues Efficient and equitable markets	Innovation Infrastructure investment Reduction in emissions
Ministers & MPs	
Security of supply Reliable supply of electricity Efficient and equitable markets Industry leadership	Investment in infrastructure and technologies Environment Good regulatory outcomes
Local Government	
Compliance Environment Coordination between utilities	Sustainable business Support for economic growth in the area
Community	
Good corporate citizenship Community sponsorship Electricity safety programme Visual and environmental impact	Engagement on community-related issues Improvement in neighbourhood environment

Energy Industry	
Participation in industry forums Leadership Innovation	Policy inputs Influencing regulators and government Sharing experience and learning
Transpower	
Effective relationships Ease of doing business Secured source of supply	Well maintained assets at the networks interface Co-ordinated approach to system planning and operational interfaces Sharing experience and learning
Media	
Effective relationship Access to expertise	Information on company operations

Table 1-4 : Stakeholder expectations

Vector ascertains its stakeholders' expectations by, amongst other things:

- Meetings and discussion forums;
- Consumer engagement surveys;
- Engagement with legislative consultation processes;
- Employee engagement surveys;
- Annual planning sessions;
- Direct liaison with customers;
- Membership on industry working groups;
- Feedback received via complaints and compliments;
- Local community meetings;
- Investor roadshows and annual general meetings;
- Analyst enquiries and presentations;
- Monitor analyst reports;
- Media enquiries and meetings with media representatives; and
- Monitoring publications and media releases.

Vector accommodates stakeholders' expectations in its asset management practices by, amongst other things:

- Providing a safe and reliable distribution network;
- Quality of supply performance meeting consumers' needs and expectations;
- Optimisation of capital and operational expenditures (capex and opex);
- Maintaining a sustainable business that caters for consumer growth requirements;
- Comprehensive risk management strategies and contingency planning;
- Due consideration of the health, safety and environmental impact of Vector's operations;
- Compliance with regulatory and legal obligations;
- Security standards reflecting consumers' needs and expectations;
- Network growth and development plans;

- Provision of accurate and timely information;
- Development of innovative solutions; and
- Comprehensive asset replacement strategies.

1.6.2 Addressing Conflicts with Stakeholder Interests

In the operation of any large organisation with numerous stakeholders with diverse interests, situations will inevitably arise where not all stakeholder interests can be accommodated, or where conflicting interests exist. From a Vector asset management perspective, these are managed as follows:

- Clearly identifying and analysing stakeholder conflicts (existing or potential);
- Having a clear set of fundamental principles drawing on Vector's vision and goals, on which compromises will normally not be considered (see the list in Section 1.3);
- Effective communication with affected stakeholders to assist them to understand Vector's position, as well as that of other stakeholders that may have different requirements; and
- Where Vector fundamentals are not compromised, seeking an acceptable compromise, or commercial solution.

Other aspects considered when assessing aspects impacting on stakeholder interests or resolving conflicts include:

- Cost/benefit analysis;
- Central and local government interface and policies;
- Commercial and technical regulation;
- Long-term planning strategy and framework;
- Environmental impacts;
- Societal and community impacts;
- Legal implications;
- Sustainability of solutions (technically and economically);
- Works/projects prioritisation process;
- Security and reliability standards;
- Quality of supply;
- Risks; and
- Work and materials standards and specifications.

1.7 Asset Management Structure and Responsibilities

1.7.1 Senior Level Organisation Structure

The Vector senior level organisation structure is provided in Figure 1-8 below. The Vector group is split into several functional areas, each with a responsible general manager.

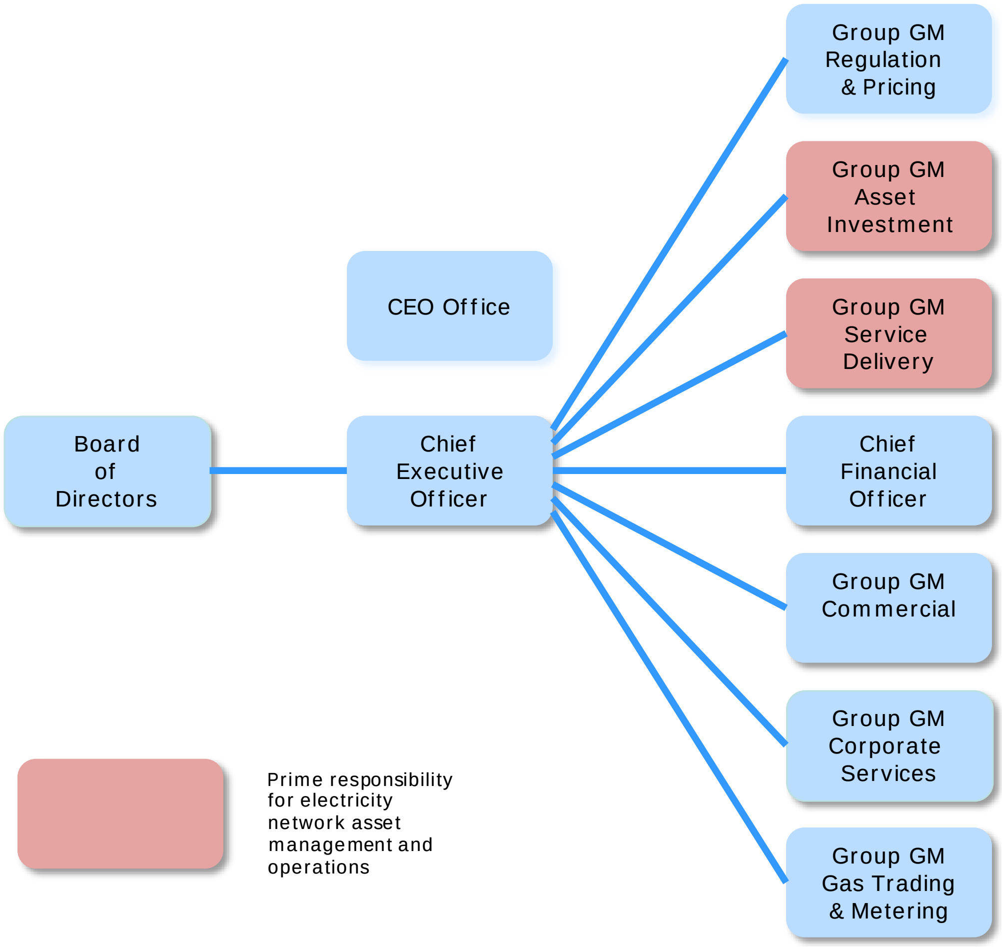


Figure 1-8 : The Vector senior management structure

The primary responsibility for the asset management of the electricity distribution network lies with the Group General Manager Asset Investment. The service provider function for the electricity network is primarily fulfilled by the SD group, under the Group General Manager Service Delivery. The role these two sections play in asset management is further discussed in Section 1.7.2 and Section 1.7.3.

In summary, the responsibilities of the other groups are as follows:

- CEO Office

  Public affairs; company secretary; economic advisor and corporate growth initiatives.

- Regulation and Pricing

  Responsible for interaction with the industry regulators, monitoring regulatory compliance, developing regulatory strategies, making regulatory submissions, setting electricity pricing, developing pricing strategy and asset valuation.

- Finance

  Financial accounting and reporting, budgeting, treasury, management accounting, group legal services, corporate risk management, investor relations, business analytics and insurance.

- Commercial

  Key customer relationships, mass market customer relationships, customer connections, public relationships, commercial strategies, Vector Communications and energy consumption projections.

- Corporate Services

  Human resource management, training and development, recruitment, health, safety and environmental policies, personnel performance management, business and data systems, IT support, computer hardware and software support and maintenance, cyber-security and communication networks.

- Gas Trading and Metering

  Wholesale gas business, liquid petroleum gas (LPG) business and metering services.

1.7.2 The Asset Investment Group

As the Asset Manager, the primary responsibility for the management of the electricity network and preparation of the AMP lies with the AI group. In broad terms, this group is responsible for:

- Ensuring asset investment is efficient and provides an appropriate commercially sustainable return to the company's shareholders;
- Ensuring the configuration of the electricity network is technically and economically efficient, meets customer requirements, and is safe, reliable and practical to operate;
- Planning network developments to cater for increasing electricity demand and customer requirements;
- Ensuring the integrity of the existing asset base, through effective renewal, refurbishment and maintenance programmes;
- Keeping abreast of technological and consumption trends, assessing the potential impact thereof and devising strategies to effectively deal with this in the long-term network planning;
- Maintaining current and accurate information about the extent and performance of the network and assets;
- Maintaining good strategic relationships with local government bodies and major infrastructure providers to support the long-term protection of Vector's assets by ensuring that obligations (from all perspectives) are well understood and met, works are co-ordinated and best mutual outcomes are sought; and
- Ensuring that Vector's obligations to the Auckland Electricity Consumer Trust (AECT) with regard to undergrounding networks in the Southern region are met.

The AMP is the prime document that captures how the above functions are discharged.

In Figure 1-9 the structure of the AI group is expanded, emphasising the electricity network asset management responsibilities.

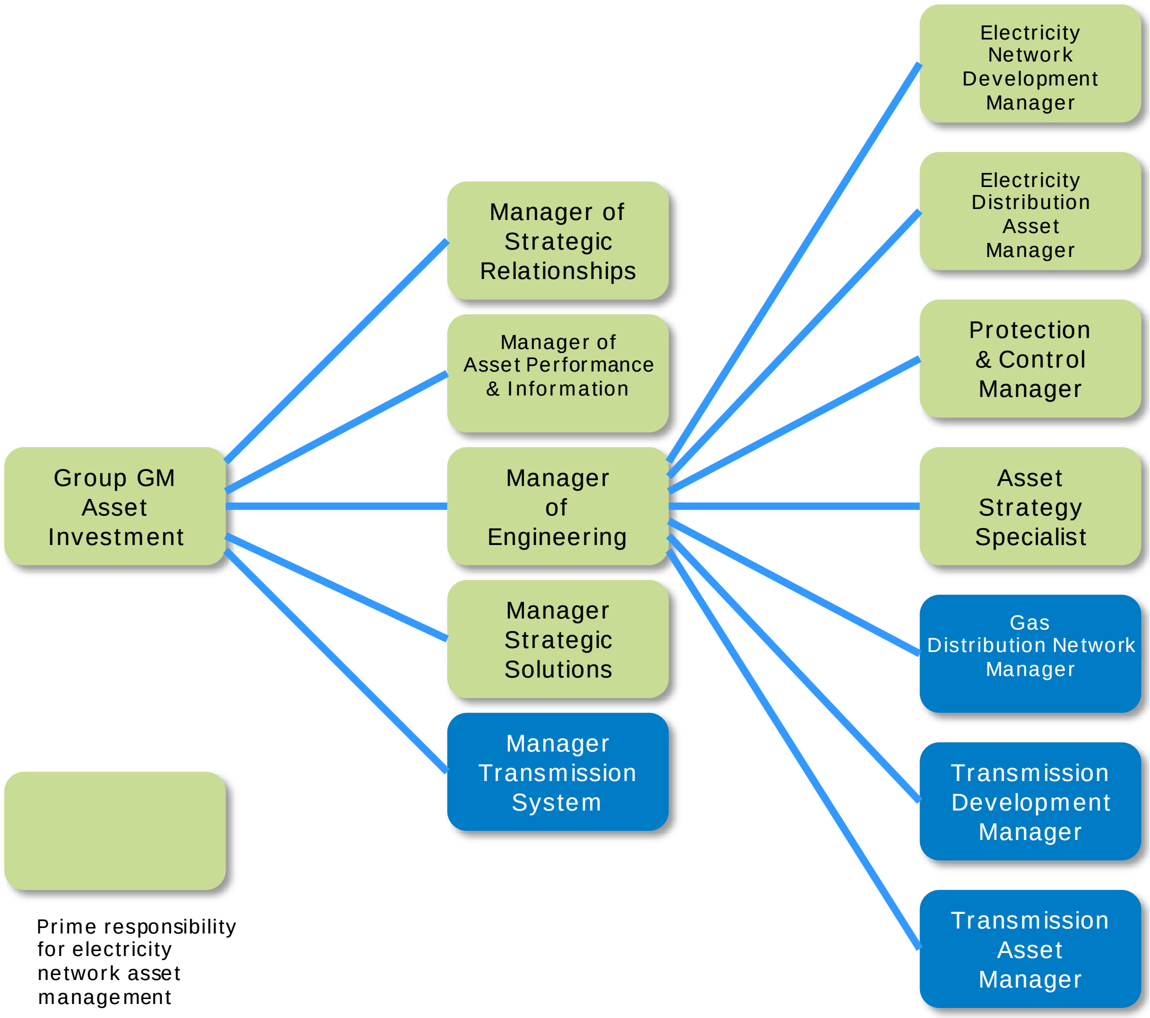


Figure 1-9 : The Asset Investment management structure supporting the AMP

1.7.3 The Service Delivery Group

In Vector's asset management model, the service provider function is predominantly fulfilled by the SD group. In conceptual terms, the AI team defines what assets are required, when and where, and how these should be operated and maintained, while the SD group delivers on providing, operating and maintaining the assets.

The SD group has a wide brief but the key functions as far as it relates to asset management, or the provision of the service provider function for the electricity network, are illustrated in Figure 1-10 and further expanded below.

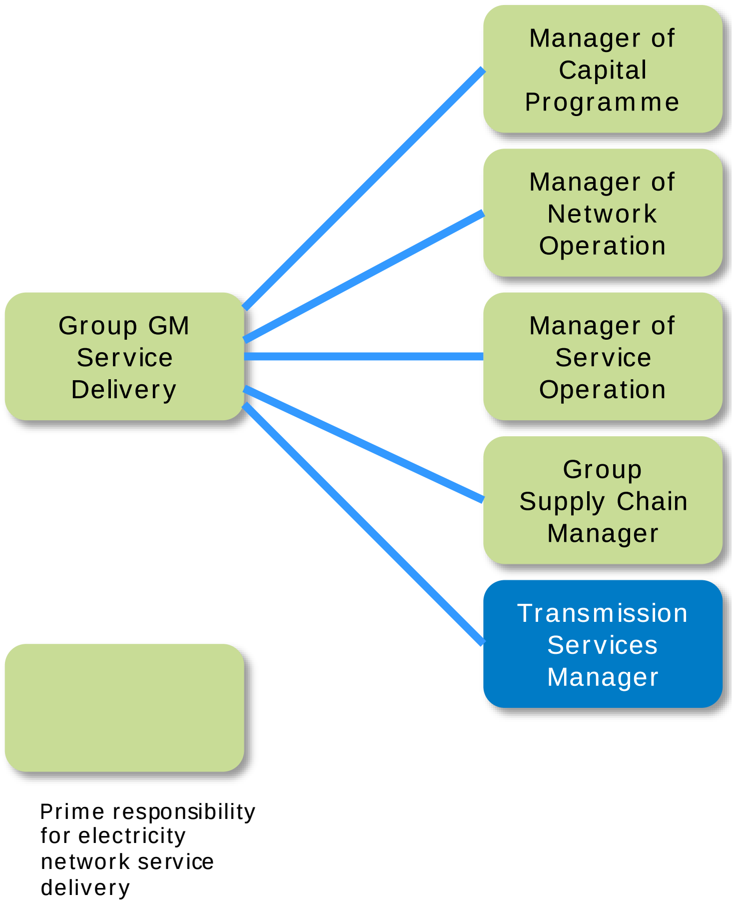


Figure 1-10 : Service Delivery as an Asset Management Service Provider

1.7.3.1 Network Operations

The Network Operations section is responsible for the day-to-day operational management of the network. It includes the control room, from where network operations are monitored and operational instructions are issued. Other functions include managing, reporting and investigating outages; switching on the network to ensure optimal configuration or to maintain supply during asset outages; and network switching during commissioning of new assets.

As the prime "operator" of the network, this team interacts closely with the Asset Manager, particularly on the following:

- Defining user requirements;
- Planning network configuration;
- Setting safe asset operation levels (short and long-term);
- Investigating outages and the root causes – especially if asset-related; and
- Contingency management.

1.7.3.2 Capital Programme

The Capital Programme section is responsible for the delivery of large infrastructure projects and is a key partner to AI in the end-to-end asset creation/replacement processes. It provides detailed project engineering and cost estimates, as well as project and contract management services. Vector does not have an in-house construction section for the electricity network - construction work is predominantly undertaken through external providers through a competitive tender process, or by our contracted service providers Northpower and Electrix (who were also selected through a competitive tender process).[7]

The Capital Delivery team and AI group have numerous touch-points, particularly the following:

- Managing the end-to-end project delivery process;
- Work scopes and project briefs;
- Detailed project engineering, including appointment of design consultants;
- Detailed project cost estimation;
- Reporting on project progress;
- Expenditure tracking and forecasting;
- Construction and commissioning standards; and
- Project close-out and capturing learning.

The AI engineering group manages the overall capital budget and is responsible for setting and controlling this, including obtaining the necessary expenditure approvals through the Vector governance process. After expenditure is approved, Capital Delivery manages the individual projects and associated expenditure.

1.7.3.3 Service Operations

The Service Operations section is responsible for the maintenance of the electricity network. This is done in conjunction with Vector's service provider partners (Northpower and Electrix), who carry out all physical work in the field.

The Service Operations section interacts with asset management in various areas, including:

- Implementation of the maintenance policies;
- Providing asset information for AI to set maintenance budgets;
- Managing replacement of mass assets (eg. poles, cross-arms or distribution transformers)[8], including project progress and expenditure reporting;
- Feedback on asset performance; and
- Investigating asset failures.

1.7.3.4 Procurement

The Procurement section manages procurement of major assets for Vector. Since the bulk of these assets are procured for capital delivery projects this activity is closely linked to asset management, including:

- Preparation of asset (contract) specifications;
- Selection of equipment suppliers;
- Supply line negotiation;
- Tender awards; and

---

[7] Works provided by our contracted service providers are still managed through a competitive bid process, although it may not be put out to open tender on a project by project basis.

[8] These mass-replacement works are not included in the large projects that are managed through the Capital Delivery group.

- Equipment cost-estimation.

1.7.4 Asset Management Activities by other Groups

While the bulk of electricity network asset management activities are performed by the AI group, supported by the SD group, as noted in Section 1.5 the rest of Vector has many inputs. Most of these inputs are indirectly related to the assets themselves, but there are the following exceptions, where electricity-related assets are directly sourced and incorporated by others.

1.7.4.1 Commercial

The Commercial group is responsible for new customer connections and the revenues derived from these assets. For large connections, which require core network extensions or could have material capacity implications, the installations are generally managed by AI and SD groups as part of the normal core network growth projects[9]. Provision of smaller, non-standard connections is directly managed by the Commercial group – through the Vector service providers. Routine connections are managed by the SD group (through the Vector service providers), under the guidance of the Commercial section.

The Commercial group is also responsible for setting and measuring the service experience that customers on our networks should receive for connections and faults.

Lastly, the Commercial group manages Vector's relationship with Transpower – a key service provider.

1.7.4.2 Information Technology (part of Corporate Services)

There is increasing overlap in the real-time operation of electricity network assets and corporate-wide information technology services. Not only does asset management require increasingly sophisticated information systems, but the traditional SCADA networks are, over time, becoming less of a stand-alone electricity network application with unique requirements and protocols, and more of a conventional IT network application. Increased security of both SCADA and Communications has to be provided for.

Procurement and implementation of IT support systems, and the core SCADA equipment, is managed by the Information Technology group.

1.7.4.3 Vector Communications (part of Commercial)

Vector Communications manages Vector's fibre optic network, for internal and external clients. They provide a major part of the SCADA network – the communication link between field devices and the central control stations.[10] Provision of this service is on a strict commercial basis, with the AI group treated similar to external clients and charged on the same basis.

1.7.5 Field Service Model

Vector's business model for operating and maintaining its electricity network assets is to outsource this work to Field Services Providers (FSPs).

[9] The Commercial group remains responsible for the contractual and commercial arrangements.

[10] Not all of the SCADA communication is provided over fibre optic communications. There is still a substantial pilot wire system in place and radio links are also used.

After an extensive investigation in 2008/09 it was decided to retain the outsourcing model. Through a competitive process, Vector selected two FSPs, viz., Electrix Ltd as the maintenance contractor for the Northern region and Northpower Ltd as the maintenance contractor for the Southern region. These two FSPs are responsible for the preventative, corrective and reactive maintenance works of the electricity network.

Other outcomes of the review included establishing new key performance indicators (KPIs) and a new framework with guiding principles to manage the working relationships between Vector and the FSPs. The objective of the new business model is to improve the efficiency and quality of the delivered services to Vector and its customers.

1.8 AMP Approval Process

Approval of the disclosure AMP is sought at the March Board meeting.

The AMP is subject to a rigorous internal review process, initially within the AI group (the developer of the plan), and then by the Regulatory, Commercial, Financial and SD groups. Finally, the AMP is reviewed and certified by the Board, in accordance with the Information Disclosure[11] requirements.

1.8.1 Alignment with the Vector Budgeting Process

Vector operates under a July to June financial year. The internal asset management planning processes and documents form a key input into the budgeting process. These contain detailed, prioritised breakdowns of the electricity network expenditure requirements identified by AI for the next five years, with supporting evaluation for the individual projects or programmes. This is intended to assist the executive with the budget process, clarifying the electricity network priorities and also prioritising these along with other business investment needs.[12] The regulatory regime and economic conditions impact on the return Vector is able to make on its assets, which in turn determines the extent to which Vector is able to invest in its networks.

The disclosure AMP, as previously discussed, draws from the internal asset management plans and processes, and it therefore represents the same view on future network requirements, including capital and maintenance expenditure requirements at the time of its preparation. However, the disclosure AMP is prepared for a regulatory timeframe, which does not correspond with Vector's financial years. There are therefore timing differences between the ten year forecasts in Vector's internal plans and this AMP.

1.8.2 The Expenditure Forecasting Process

In Figure 1-11 the forecast process for capex projects in the AMP is illustrated. This process follows the following steps:

- The overall capital works programme is divided into different work categories. A plan covering the next five-year period is first developed for each work category (based on the asset management criteria for that work);
- A works programme is then drawn up and the corresponding capex to implement the works programme is developed. This is an unconstrained estimate;

---

[11] Requirement 7(1) of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008.

[12] As with all companies, Vector does not have unrestrained cash resources, and competing investment needs and commercial opportunities have to be balanced.

- The prioritisation process described in Section 9 is then applied to the projects and programmes within the work category. This identifies projects that could be left out from the programmes without undue negative consequences. Through this, it is possible to set an upper and lower boundary for the expenditure levels; and
- An overall prioritisation process is then applied to the combined suite of network projects, to develop the final AMP forecast for combined capex.

As noted before, the accuracy of forecasts further out in the planning period diminishes. The capital forecasts for years six to ten are based on a combination of projects foreseen at this stage and trend analysis for other types of projects. Project prioritisation for this period is indicative only.

A similar process is adopted for the operation and maintenance expenditure forecasts, which are prepared in conjunction with Service Delivery.

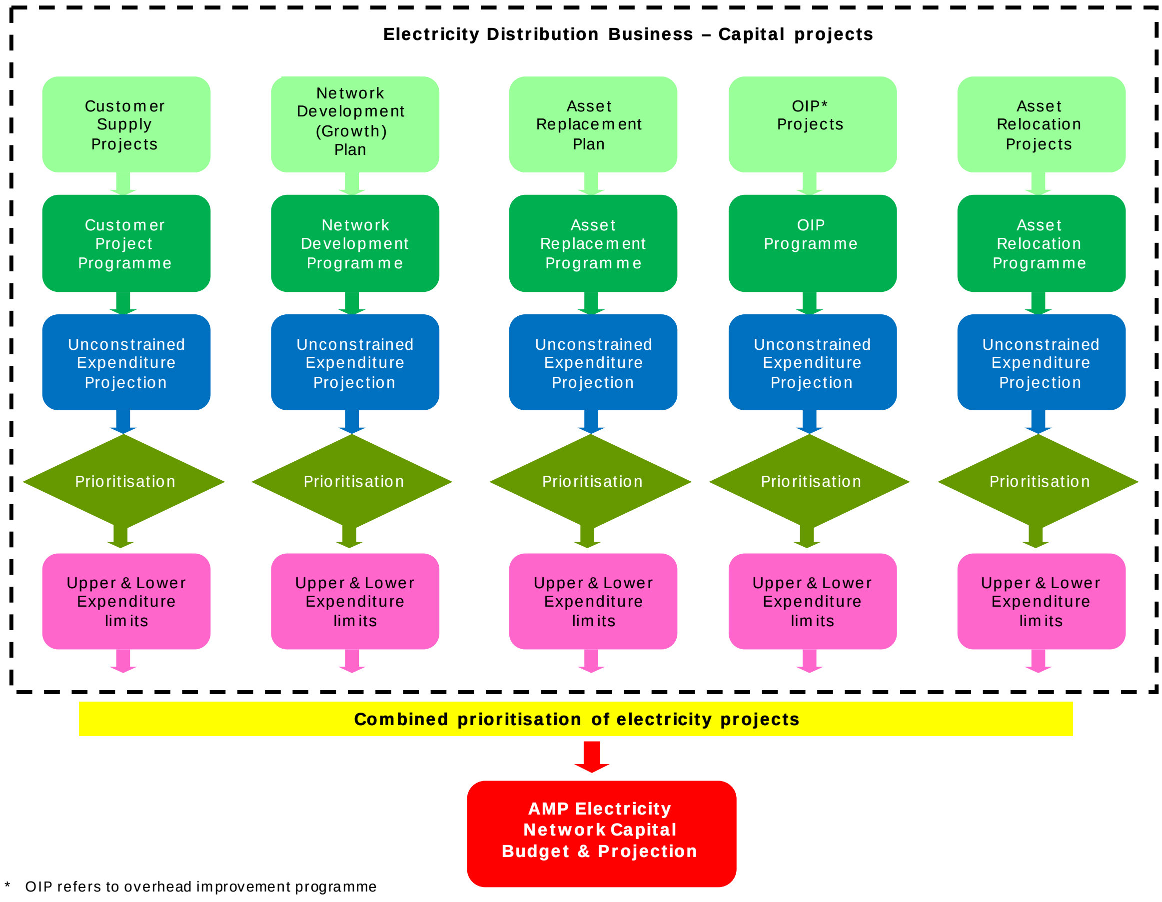


Figure 1-11 : Capex forecasting process adopted for the AMP

1.9 Asset Management Decisions and Project Expenditure Approval

Implementation of the AMP requires decisions to be made by management and staff at all levels, reflecting their functional responsibilities and level of delegated financial authorities (DFAs), as set in accordance with the Vector governance rules. Functional responsibilities define the role of each staff in the organisation. The DFAs specify the level of financial commitment that individuals can make on behalf of the company.

Investment decisions are budget-based, with the Board approving yearly budgets before any commitment can be made. Preliminary project approval is normally given through the annual (one-year) budgeting process, but projects are not individually assessed in detail at this stage. Project-specific capex approval therefore still has to be granted for all projects prior to committing capital, despite these having been included in the approved annual budget. The detailed project approval process has been developed in accordance with the Vector DFA system.

Critical unbudgeted investments are be taken to the Board for consideration at any stage of the financial year, if supported by a robust business case or arising from an urgent safety, reliability or compliance issue.

Applications for expenditure approval must be supported by formal business cases. This business case contains information on the expenditure objective, constraints and assumptions, strategic fit, options investigated, project time line, resources required and available, project deliverability, cost benefit analysis, return on investment and risk assessment. This assists Vector management to assess and approve investment applications.

1.10 Progress Reporting

Performance against the annual budgets is closely monitored, with formalised change management procedures in place. Regular reports are sent to the Vector Board regarding:

- Monthly report on overall expenditure against budget;
- Progress of key capital projects against project programme and budget;
- Reliability performance – SAIDI, SAIFI, CAIDI;
- Performance and utilisation of key assets such as sub-transmission cables, distribution feeders, power transformers, etc;
- Progress with risk register actions (the board has a risk committee with a specific focus on risks to the business);
- Health, safety and environmental issues; and
- Network reliability.

1.11 Asset Management Processes

The diagram in Figure 1-12 shows the high level asset investment process within Vector. This highlights the relationship between the different asset creation and evaluation processes within Vector.

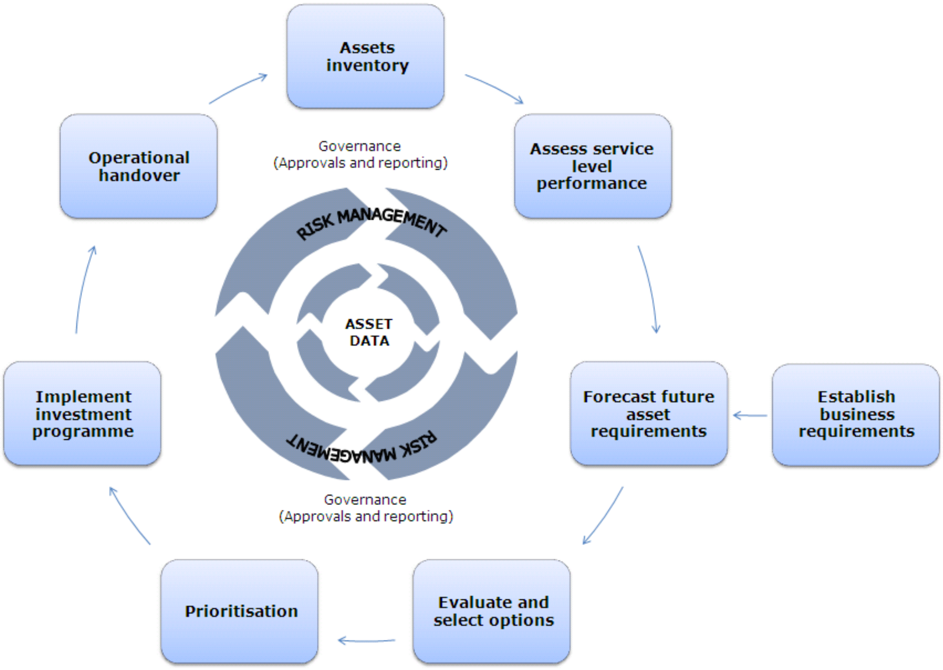


Figure 1-12 : High-level overview of the Vector asset investment process

Assets Inventory

Information on the quantity, age and capability of existing assets is essential to understand and effectively manage the asset base. Information on the existing assets and network configuration is set out in Section 2 and Section 6 of this AMP.

The asset register, geographical information system (GIS) and associated databases store cost information and technical characteristics for all assets, including their location, history and performance. The way in which information systems support asset management processes is described in Section 7.

Assess Service Level Performance

Information on the performance, utilisation and condition of existing assets and the different parts of the network is needed to forecast future investment, renewal or upgrading requirements and improve service level. This requires ongoing monitoring of asset condition and network performance, the consumption of resources associated with maintaining the assets, and the efficiency and effectiveness with which assets are utilised (including network configuration). Information on the condition and performance of existing assets and on the network configuration is set out in Section 4, Section 5 and Section 6.

Establish Business Requirements

The levels of service required from the electricity network are guided by the wider business requirements. These requirements in turn are determined by Vector's operating environment and reflect corporate, community, environmental, financial, legislative, institutional and regulatory factors together with stakeholder expectations.

Section 1 sets out the background and business requirements that drive the AMP. Service levels are described in Section 4 and Section 5.

Forecast Future Asset Requirements

The combination of asset condition and performance drivers, load demand and the business requirement driver form the basis for assessing future asset needs and the resulting network development plans. Section 4, Section 5 and Section 6 discuss this information.

Vector operates an electricity network in a changing environment, and future requirements are likely to differ materially from the situation faced today. Such changes have to be anticipated in current development plans. Section 3 discusses the anticipated impact of future technology on the network, and Vector's development strategies to position for this.

Evaluate and Select Options

Once the future network or asset requirements are established, options for addressing these needs have to be evaluated and potential solutions have to be identified. Decision tools and systems used to support the evaluation of options include loadflow analysis, effective capital budgeting techniques, optimised renewal modelling, life-cycle costing, risk assessments and geographic information. At the same time, the feasibility of non-network or unconventional solutions to address network requirements is also considered.

Vector broadly categorise asset investment planning in two main streams:

- Network development planning is undertaken to ensure service target levels are met in an environment of increasing load (demand) growth, or increased customer quality expectations. It is based on systematic analysis of maximum demand trends, consumer requests and demographic estimates. Vector's approach to network development planning is set out in Section 5; and
- Maintenance planning is undertaken to ensure assets remain fully functional for their reasonably expected lifespan when operating within expected design ratings. It also includes activities to prolong asset lives or to enhance asset performance. Maintenance planning addresses both capital investments on renewal or refurbishment, or long, medium and short-term asset maintenance. Vector's approach to maintenance planning is set out in Section 6.

Prioritisation

Prioritisation is a process that ranks all projects identified during the network development and maintenance planning processes. This process ensures only projects that meet Vector's investment thresholds – which encompass commercial, safety and technical considerations - are included in the project programme.

Projects also undergo a second prioritisation process, to compare investment needs across the company. This is to ensure the best use of available resources on a company-wide basis.

The way Vector prioritises electricity capital investment projects is discussed in Sections 5, 6 and 9.

Implement Investment Programme

Budgets are prepared on a cash-flow basis mirroring expected expenditure based on works programmes. The Board approves the overall expenditure on an annual cycle and project expenditure on the larger projects in accordance with DFA governance rules. While most projects are delivered in the financial year, the delivery of larger projects, such as new zone substations (a substation containing equipment at sub-transmission voltage, sub-transmission voltage includes 110kV, 33kV and 22kV), may straddle financial years. Budgetary provision is made in the year expenditure will be incurred.

The implementation of solutions identified as part of the asset replacement (Section 6) or planning process (Section 5) are managed by the SD and Commercial (for customer connections) groups. For larger projects, the Capital Programme team, as part of the SD group, develops the conceptual solution into a detailed design suitable for implementation. Contracts are let to approved service providers (following a competitive tender process) for the execution of these projects.

Service Operations (a team within the SD group) manages the bulk replacement and maintenance programmes, liaising directly with the service providers while the Customer Solutions team in the Commercial Group manages the customer connections with the service providers.

Operational Handover

Once construction and installation is completed, a formal handover process takes place. The process is designed to check the quality of work and equipment meets Vector's standards and the assets are constructed to allow maintenance in accordance with Vector's Operation and Maintenance Manuals. It also includes a walkover between the project manager and AI group asset specialists who take assets over and arrange the maintenance regime. The GIS is updated with the new assets as well as the technical asset master (TAM) database.

Governance (Approvals and Reporting)

Formal approval (budgets and expenditures) and reporting (progress and risks) processes are in place to satisfy Vector's Corporate Governance requirements (Section 1).

Risk Management

Risk management which underpins all asset management business processes and forms an important part in defining project requirements is discussed in Section 8.

1.12 Works Coordination

1.12.1 Internal Coordination

Over the last few years, Vector has put extensive effort into continuously improving the coordination of the various activities associated with the delivery of the capital works programme with the objective of better utilisation of resource, enhancing capital efficiency and delivering improved customer outcomes. Improvement initiatives have included:

- Deployment of the "Project Server" to capture project and resource information and to track project progress against schedule from the conception stage through to commissioning and hand-over to operations;
- Establishing and refining the project "end-to-end" process to improve visibility of the delivery performance on capital projects;
- Development of enhanced "project solution studies" to ensure optimal project outcomes; and
- Improved processes and communication between project initiators, network planners, asset specialists, designers and contract managers.

In addition to its electricity networks, Vector operates gas distribution networks, a gas transmission system and a fibre optic telecommunication network. To maximise the synergy benefits that can be achieved from cooperation, and to deliver projects in the most effective, least disruptive manner, effective coordination of capital works between these business units is essential. Significant improvement in delivery has been achieved over the last couple of years through the implementation of these initiatives.

1.12.2 External Coordination

As well as internal coordination, new processes have also been put in place to improve coordination between Vector and other utilities, roading authorities, local councils and their service providers. These works coordination processes are focused on maintaining effective communication channels with external agencies, identifying cost effective future proofing opportunities, minimising disturbance to the public as a result of infrastructure works, streamlining works processes and meeting Vector's regulatory obligations.

It is important for Vector to be cooperative and supportive in its relationships with other agencies. In the past this has resulted in a number of win-win outcomes, with Vector for example obtaining access to motorway corridors for laying cables.

1.13 Other Asset Management Documents and Policies

The internal asset management business plan is the main document for capturing and communicating the asset management strategies for the electricity network. As noted before, this regulatory AMP draws from that plan. In addition, Vector has a number of other documents used to capture asset management polices and particulars. Including all of these in one document would produce a totally unwieldy, impractical plan. In addition, there are a number of company-wide policies that have a direct bearing on asset management.

1.13.1 Other Asset Management Documents

The AMP is supported by a collection of detailed asset management documents and policies. These include:

- Network security standards and policies;
- Detailed asset maintenance standards;
- Network design policies;
- Network architecture;
- Risk management policies;
- Ownership policy;
- Contracts management policy;
- Procurement policy;
- Health and safety policy;
- Environmental policy;
- Asset rehabilitation policy;
- Load management plans;
- Asset settlement manual;
- Network contingency plans;

- Network projects quality assurance policy; and
- Drug and alcohol policy.

In addition to the policies, Vector has also developed a suite of work practice standards and guidelines and equipment specifications to guide its service providers in the course of implementing the works programme. These standards, guidelines and specifications can be found on our internal communications website.

1.13.2 Other Company Policies Affecting Asset Management

Vector has a number of business policies designed to help the business to operate efficiently and effectively. Many of these interact with, or impact on, the asset management policies and this AMP.

Business:

- Code of conduct;
- Legal compliance policy;
- Protected disclosure policy;
- Remuneration policy;
- Customer credit policy;
- Foreign exchange policy;
- Expense management policy;
- Network WIP (work-in-progress) Management policy;
- Network Fixed Asset Creation and Disposal policy; and
- Capex policy.

Information Technology:

- Access policies;
- Password and authentication policy;
- Network management policy;
- Internet use policy;
- E-mail policy;
- Access control policy;
- Antivirus policy;
- Communications equipment policy;
- Computer systems and equipment use policy;
- Cyber crime and security incident policy;
- E-commerce policy;
- Firewall policy;
- Hardware management policy;
- Information technology exception policy; and
- Information technology general user policy.

1.14 External Review of Vector's Asset Management Practice

Vector has, over an extended period, engaged external expert technical advisers on an annual basis to review its asset management practices. While these reviews have been very positive in their feedback – confirming asset management at Vector conforms to good industry practice – we have taken note of the feedback and recommendations received, and where practical and beneficial, reflected this in our asset management practices.

1.14.1 2010 Asset Management Practice Review

During 2010 Vector engaged SKM Australia to carry out an independent specialist review of our asset management practices. This resulted in a very positive endorsement, confirming that our practices match the very best in Australasian network management in most areas. Highlight findings included:

- Vector's asset management planning is of high quality and its AMP is the most comprehensive witnessed;
- The general condition and serviceability of the assets were good and assets were well maintained in accordance with sound industry practice;
- Planning and processes for implementing new capital works are sound and security and reliability of the power system will likely be sustained or enhanced over the next 10 years.;
- Based on current budgets and demand forecasts security, Vector's capital work programme and budgets appear sufficient to sustain capacity; and
- Vector has adopted appropriate asset management practices to minimise risk of failure on the network.

1.14.2 2010 Asset Management Plan Review

During 2010 we also engaged Utility Consultants, to review our AMP both from a content and regulatory compliance point of view. The review provided very positive endorsement of our electricity network asset management practices and strategic thinking. In particular, the consultant endorsed the approach taken to improve capital efficiency and encourage innovation, and in future-proofing the network against any adverse impact of future technologies.

Suggestions were also made on the presentation of the AMP, particularly on its alignment with regulatory disclosure requirements. These suggestions are accounted for in this current AMP.

1.14.3 Improvement opportunities identified in the asset management reviews

In the aforementioned independent reviews, some improvement opportunities were identified, as noted below. Vector is already addressing most of the opportunities, as noted:

- System wide demand forecasts should reconcile with energy forecasts.

  Vector has independently identified this as an improvement initiative and has formed a group-wide forecasting working group to ensure alignment between the forecasts used in all parts of the business. In addition, Vector has engaged a specialist consultant (Sapere, formerly LECG) to review our demand and energy forecasting processes and assist with the development of an improved forecasting model (see Section 5.3 for further discussion);

- The demand forecast should include a 10% PoE (probability of exceedance) forecast and a 50% PoE forecast.

  PoE has been included in the current demand forecast for single transformer substations only. Vector wishes to extend this philosophy across the wider network assets. It is foreseen that this action will be included as part of the upgrade of the Vector-wide Demand and Energy Forecast Model in the course of 2011;

- Vector should consider identifying the credible multiple contingencies or unavoidable risks in its security policy, against which network resiliency is not provided. This should take into account high impact low probability risks.

  Vector accepted this recommendation and will in future explicitly define such conditions in our network development procedures and security standards. (This is already introduced in Section 5.2 of the AMP.)[13];

- Vector to consider limiting the demand on single transformer substations to 10MVA.

  While Vector understand that this recommendation is in accordance with Australian best practice recommendations, it is noted that sufficient backstop capacity exists on our 11kV network to retain supply in case of a transformer failure, even where substations are loaded at above 10MVA. Where economically justifiable, Vector will however consider placing limits on the load at risk; and

- Vector should consider implementing more detailed post-implementation project reviews.

  A process to ensure post-implementation project review occurs in future is being developed for company-wide application. We expect to implement this during 2011.

1.15 Cross Reference to the Information Disclosure Requirements

As indicated earlier (Section 1.1), this disclosure AMP was prepared based on Vector's internal asset management business plan. As such the order of presentation of this disclosure AMP is somewhat different from that presented in the Electricity Information Disclosure Handbook (31 March 2004 as amended 31 October 2008).

The following table provides a cross reference between the disclosure requirements and the sub-sections in this AMP. A column "Interpretation" is included in the table to elaborate on the "Handbook Requirements" with the aim of helping the reader to locate the appropriate sections in the AMP against the detailed requirements as specified in the Handbook. The "Interpretation" is based on the description given by the Commerce Commission's Asset Management Plan (2009 – 2019) compliance review.

[13] It was acknowledged that credible contingency events are well-understood by the Vector electricity team, as well as the risks associated with these. Where the risks cannot be fully mitigated they are actively managed. Major risks are also identified in the company risk register.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.4.5	The disclosed AMP must: a) Enable the suitability of asset management practice and assets for current and future service; b) Specifically support the achievement of disclosed service level targets; and c) Provide a sound basis for ongoing risk assessment. *Explanation: Disclosed AMPs must be presented in a manner that meets the needs of external users.*	Does the disclosed AMP meet the needs of external users	This AMP has been reviewed and edited by a professional writer to ensure ease of use by external users.
4.4.6	Disclosed AMPs must clearly identify limitations in availability or completeness of information, and include: a) details of the basis for asset management planning, including assessment of the methodologies used; b) the information required by Requirement 7(2); and c) Details of plans for improvement in information quality. *Explanation: The detail and accuracy of information available will vary. Information gaps should be specifically addressed to enhance the transparency of disclosure, place emphasis on identifying deficiencies and promote improvement.*	Are information gaps specifically addressed to enhance the transparency of disclosure, is there an emphasis on identifying deficiencies and promoting improvement.	Sections 7.2 and 7.4
		Does the AMP comment on the completeness or accuracy of the asset data and does it identify any specific areas where the data is incomplete or inaccurate?	Sections 6.3 and 7.3
4.4.6c		If there is a problem with data accuracy or completeness, does the AMP disclose initiatives to improve the quality of the data?	Sections 7.2 and 7.4
4.4.3 4.5.1	AMPs must include a summary. *Explanation: The inclusion of a summary aids understanding and readability, and also provides an opportunity for EDBs to emphasise important content.* Summary of the AMP The AMP is to include a summary that provides a brief overview of the contents of the plan and highlights information that the EDB considers significant.	Does the AMP include a summary that provides a brief overview of the AMP contents?	Executive summary
4.4.4	Disclosed AMPs must consist of a single document containing all information necessary to allow the document to be fully understood by a	Does the AMP summary highlight	Executive summary

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.1	reader with a reasonable understanding of the management of electricity distribution assets. *Explanation: Disclosure of AMPs as a single document will prevent disclosure of disjointed, poorly coordinated material that is difficult to understand. In some cases EDBs may choose to include other documents in their disclosed AMP for example, separate network development plans. This does not necessarily require integration of separate plans into a single framework if the linkages between parts of the plan are made and indexed.* Summary of the Asset Management Plan The AMP is to include a summary that provides a brief overview of the contents of the plan and highlights information that the EDB considers significant.	information that the EDB considers significant?	
4.5.2a	The AMP must include details of the asset management plan background and the objectives of the EDB's asset management and planning processes including: a) the purpose of the plan; *Explanation: For some EDBs the disclosed AMP is also a key internal planning document. Other EDBs base their asset management processes around other planning documents and produce the disclosed AMP purely to meet regulatory requirements. The purpose statement should clearly state the intention of the business in preparing the disclosed document. If the AMP is intended to describe asset management processes documented elsewhere in order to meet information disclosure requirements, this should be stated; otherwise the wider purpose of the document and the manner in which it is used by the EDB should be described. It should be noted that the objective of the AMP disclosure requirement is to encourage the development of best practice asset management processes. Therefore the disclosed AMP must contain sufficient information to allow stakeholders to make an informed judgement as to the extent that an EDB's asset management processes meet best practice criteria. The purpose statement should also state the objectives of the EDBs asset management and planning processes. These should be consistent*	Does the AMP contain a purpose statement?	Section 1.3
4.5.2a		Does the purpose statement make the status of the AMP clear? For some businesses the AMP will be the key document that guides the asset management process. Other businesses will have a different asset management system in place and will write the disclosed AMP purely to meet the disclosure requirements.	Sections 1.1 and 1.3
4.5.2a		Does the purpose statement also include the objectives of the EDB's asset management and planning process? To what extent are these objectives consistent with the EDB's vision and mission statements? Do the objectives show a clear	Sections 1.3, 1.4, 1.5, 1.6, 1.8, 1.9 and 1.11.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	with the EDB's vision and mission statements, and show a clear recognition of stakeholder interest.	recognition of stakeholder interest?	
4.5.2bi	b) a description of the interaction between those objectives and other corporate goals, business planning processes, and plans; *Explanation: Best practice asset management and planning processes are integrated with other business plans and goals. The AMP should describe this relationship. In particular, it should:* *(i) state the high level corporate mission or vision as it relates to asset management;* *(ii) identify the documented plans produced as outputs of the annual business planning process adopted by the EDB; and* *(iii) describe how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management.*	Does the AMP state the EDB's high level corporate mission or vision as it relates to asset management?	Section 1.3
4.5.2bii		Does the AMP identify the documented plans produced as outputs of the EDB's annual business planning process?	Section 1.3
4.5.2biii		Does the AMP show how the different documented plans relate to one another with particular reference to any plans specifically dealing with asset management?	Sections 1.1, 1.3, 1.8 and 1.13.
4.5.2b		How well are the objectives of the EDB's asset management and planning processes integrated with its other business plan and goals and how well does the AMP describe this relationship?	Sections 1.3, 1.5, 1.6, 1.8, 1.9, 1.10, 1.11 and 1.12.
4.5.2c **7(3)a**[14]	c) the period covered by the plan, and the date the plan was approved by the board of directors of the EDB; *Explanation: The AMP must cover at least a projected ten year asset management planning period. Good asset management practice recognises the greater accuracy of short-to-medium term planning, and will allow for this in the AMP. Hence the asset management plans for the second five years of the asset management planning period need not be presented in the same detail as the near term plans.*	Does the AMP specifically state that the period covered by the plan is ten years or more from the commencement of the financial year?	Section 1.2
4.5.2c **7(1)d**[11]		Does the AMP state the date on which the AMP was approved by the Board of Directors?	Section 1.2

[14] Disclosure relating to Asset Management Plans (part 7) of the Electricity Distribution (Information Disclosure) Requirements 2008

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.2.d	d) a description of stakeholder interests (owners, consumers etc); *Explanation: Recognising and accommodating stakeholder interests are key parts of the AMP. AMPs should therefore identify important stakeholders and indicate:* *(i) how the interests of stakeholders are identified;* *(ii) what these interests are;* *(iii) how these interests are accommodated in asset management practices; and* *(iv) how conflicting interests are managed.*	Does the AMP identify the EDB's important stakeholders and indicate:	Sections 1.4, 1.5 and 1.6
4.5.2.di		- how the interests of stakeholders are identified;	Section 1.6
4.5.2.dii		- what these interests are;	Sections 1.5 and 1.6
4.5.2.diii		- how these interests are accommodated in the EDB's asset management practices: and	Sections 1.5 and 1.6
4.5.2.div		- how conflicting interests are managed?	Sections 1.5 and 1.6
4.5.2ei	e) a description of the accountabilities and responsibilities for asset management within the EDB; and *Explanation: An AMP should consider the accountability and responsibility for asset management on at least three levels:* *(i) governance;* *(ii) executive; and* *(iii) field operations.* *At the governance level, the AMP should describe the extent of Board approval required for key asset management plans and decisions and the extent to which asset management outcomes are regularly reported to the Board.* *At the executive level the AMP should provide an indication of how the in-house asset management and planning organisation is structured.* *At the field operations level it should comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.*	At the governance level, does the AMP describe the extent of Board approval required for key AMPs and decisions and the extent to which asset management outcomes are regularly reported to the Board?	Sections 1.1, 1.8, 1.9, 1.10 and 1.12
4.5.2eii		At the executive level, does the AMP provide an indication of how the in-house asset management and planning organisation is structured?	Section 1.7
4.5.2eiii		At the field operations level, does the AMP comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used?	Sections 1.1 and 1.7
4.5.2f	f) details of asset management systems and processes, including asset management systems/software and information flows.	Does the AMP identify the key systems used to hold data used	Sections 7.1, 7.2 and 7.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: The key systems used to hold asset data used in the asset management process should be identified, with the data held in each system and what it is used for. Good asset management practice requires that all assets are identified and the asset type, capacity and condition recorded. The AMP should identify areas where asset data is incomplete or inaccurate, and should disclose any initiatives to improve the quality of this data. *The processes used within the business for:* *(i) managing routine asset inspections and network maintenance;* *(ii) planning and implementation of network development projects; and* *(iii) measuring network performance for disclosure purposes should be described.*	in the asset management process? Does it describe the nature of the data held in each system and what this data is used for?	
		Does the AMP describe the processes used within the business for: managing routine asset inspections and network maintenance; planning and implementation of network development processes; and measuring network performance (SAIDI, SAIFI) for disclosure purposes?	Sections 1.11, 4.1, 5.1, 5.3, 6.2 and 6.3.
4.5.3ai	The AMP shall include details of the assets covered including: a) a high-level description of the distribution area; *Explanation: The AMP should describe at a high level the distribution areas covered by the EDB and the degree to which these are interlinked. The description should include:* *(i) the distribution area(s) covered;* *(ii) identification of large consumers that have a significant impact on network operations or asset management priorities;* *(iii) description of the load characteristics for different parts of the network; and* *(iv) the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.*	Does the high level description of the distribution area include: - the distribution areas covered;	Section 2.1
4.5.3aii		- identification of large consumers that have a significant impact on network operations or asset management priorities;	Section 2.1
4.5.3aiii		- description of the load characteristics for different parts of the network; and	Sections 2.1 and 2.2
4.5.3aiv		- the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any?	Section 2.2
4.5.3.bi	b) a description of the network configuration;	Does the AMP include a description of the network	Sections 2.2 and 2.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: The AMP should include a description of the network configuration that should include: *(i) identification of bulk electricity supply points and any embedded generation with a capacity greater than 1 MW. The existing firm supply capacity and current peak load of each bulk supply point should be stated;* *(ii) a description of the sub-transmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the sub-transmission network. The AMP should identify the extent to which individual zone substations have n-x sub-transmission security;* *(iii) a description of the distribution system, including the extent to which it is underground;* *(iv) a brief description of the network's distribution substation arrangements;* *(v) a description of the low voltage network including the extent to which it is underground; and* *(vi) an overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.* *If non-contiguous networks exist, these should be noted and treated as separate distribution areas.*	configuration which includes: - identification of the bulk electricity supply points and any embedded generation with a capacity greater than 1 MW;	
4.5.3.bi		- the existing firm supply capacity and current peak load at each bulk supply point;	Section 2.3
4.5.3.bii		- a description of the sub-transmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the sub-transmission network;	Sections 2.3 and 5.7 through to 5.22
4.5.3.bii		- the extent to which individual zone substations have n-x sub-transmission security;	Section 2.3
4.5.3.biii		- a description of the distribution system including the extent to which it is underground;	Section 2.3
4.5.3.biv		- a brief description of the network's distribution substation arrangements;	Section 2.3
4.5.3.bv		- a description of the low voltage network, including the extent to which it is underground; and	Section 2.3
4.5.3.bvi		- an overview of secondary assets such as ripple injection systems, SCADA and Tele communications systems.	Section 2.3
4.5.3c	c) a description of the network assets by category, including age profiles and condition assessment; and	Does the AMP include a description of the assets that	Section 6.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: Each asset category used in the network should be discussed, providing at least the following information for each category: *(i) voltage levels;* *(ii) description and quantity of assets;* *(iii) age profiles;* *(iv) value of the assets in the category (which can be drawn from the ODV disclosure or other record bases kept by an EDB); and* *(v) a discussion of the condition of the assets, further broken down as appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.* *The asset categories discussed should include at least the following:* *(i) assets owned by the EDB but installed at bulk supply points owned by others;* *(ii) sub-transmission network including power transformers;* *(iii) distribution network including distribution transformers;* *(iv) switchgear;* *(v) low voltage distribution network; and* *description of supporting or secondary systems including:* *- ripple injection plant;* *- SCADA;* *- communications equipment;* *- metering systems;* *- power factor correction plant;* *- EDB owned mobile Substations and generators whose function is to increase supply reliability or reduce peak demand; and* *- other generation plant owned by an EDB.* *While asset quantities must be presented in a way that fairly describes the size of the asset base, detailed schedules similar to those presented in an optimised deprival valuation ODV) are not necessary. However, where disclosed quantities or other asset related information is based on estimates, this should be explicitly stated.*	make up the distribution system that includes, for each asset category: voltage levels, description and quantity of assets, age profiles, value of the assets in each category (which can be drawn from the ODV disclosure or other record bases kept by the EDB, and a discussion of the condition of the assets, further broken down as appropriate and including, if necessary, a discussion of systemic issues leading to premature asset replacement?	
4.5.3c		Do the asset categories discussed at least include: 1. assets owned by the EDB but installed at bulk supply points owned by others; 2. sub-transmission network including power transformers; 3. distribution network including distribution transformers; 4. switchgear; 5. low voltage distribution network; and 6. description of supporting or secondary systems including: - ripple injection plant; - SCADA;	Sections 2.3 and 6.3.

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
		- communications equipment; - metering systems; - power factor correction plant; - EDB owned mobile Substations and generators whose function is to increase supply reliability or reduce peak demand; and - other generation plant owned by an EDB.	
4.5.3d	d) the justification for the assets. *Explanation: The basic justification for an EDB's asset base is that it is the minimum required to provide electricity of sufficient capacity and reliability to all consumers, accommodating reasonable growth forecasts. Network standards could differ between different parts of a network. The extent that an existing network is over-designed is reflected in the optimisation process completed when undertaking an ODV valuation. An explanation of the network optimisation included in the last ODV report could therefore be provided to satisfy this requirement.* *EDBs may choose to include in this section a discussion on assets that are excluded from the ODV valuation in accordance with clause 2.6 of the ODV Handbook. EDBs may also discuss assets they consider to be justified, even though these assets have been optimised out of the ODV valuation on account of the optimisation requirements.*	How does the EDB justify its asset base? Comment briefly whether the AMP includes any asset justification and the nature and reasonableness of the justification provided.	Section 2.4
4.5.4a	Service Levels *Explanation: Best practice requires that any performance indicators should be objectively measurable and be suitable for applying consistently across the network and over time. All indicators used as the basis for performance targets should be clearly defined in the AMP in order for it to be a self contained document. Targets should be consistent with business strategies and asset management objectives, and be provided for each year of the AMP planning period.*	What consumer performance targets are included in the AMP? Are the targets objectively measurable, adequately defined and is the EDB proposing to improve the level of service over the period of the plan? To what extent are the targets consistent with the other plans set out in	Section 4.1

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	The disclosed AMP must include details of the proposed levels of service including: a) consumer oriented performance targets; *Explanation: As a minimum, the reliability performance measures used for threshold compliance assessment (SAIDI, SAIFI) should be included. It is preferable for consumer orientated performance targets to differentiate between different parts of the network, such as between urban and rural areas.*	the AMP?	
4.5.4b	b) other targets relating to asset performance, asset efficiency and effectiveness, and the efficiency of the line business activity; and *Explanation: This section should include technical and financial performance indicators related to the efficiency of asset utilisation and operation.*	Does the AMP disclose other targets relating to asset performance, asset efficiency and effectiveness, and the efficiency of the line business activity?	Sections 4.2 and 4.3.
4.5.4c	c) the justification for target levels of service based on consumer, legislative, regulatory, stakeholder, and other considerations. *Explanation: The basis on which the target level for each performance indicator was determined should be indicated, even if the justification is that the target is indicative of current performance levels.* *Targets should take account of stakeholder requirements and reflect what is practically achievable given current network configuration, condition and planned expenditure levels. It should be demonstrated in the AMP how stakeholder needs were ascertained and, where appropriate, translated into service level targets.*	Does the AMP include the basis on which each performance indicator was determined? Does the justification include consideration of consumer, legislative, regulatory, stakeholder requirements?	Sections 4.1 and 4.2
4.5.5a	Network Development Planning Disclosed AMPs must include a detailed description of network development plans, including: a) a description of the planning criteria and assumptions;	Does the AMP describe the planning criteria used for network developments?	Section 5.2
4.5.5a	*Explanation: Planning criteria for network developments should be described logically and succinctly. Where probabilistic planning techniques are used, this should be indicated and the methodology briefly described.* *The AMP should also describe the criteria used for determining the capacity of new equipment for different types of assets or different parts of the network. These relate to the philosophy of the business in the management of planning risk.*	Does the AMP describe the criteria for determining the capacity of new equipment for different asset types or different parts of the network?	Section 2.4
		Does the AMP describe the planning techniques used?	Section 5.2

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.5c	c) details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast load increases; *Explanation: The load forecasting methodology used should be explained, indicating all the factors used in preparing the estimates. Load forecasts should be broken down to at least the Zone Substation level, covering the whole AMP period. The impact of uncertain, but substantial individual projects/developments should be discussed and the AMP should make clear the extent to which these uncertain load requirements are reflected in the load forecast.* *Load forecasting should take into account the impact of any embedded generation or anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.* *Network or equipment constraints anticipated due to the anticipated load growth during the AMP should be identified.*	Does the AMP describe the process and criteria for prioritising network developments?	Sections 5.3 and 9.2
4.5.5c		Does the AMP describe the load forecasting methodology, including all the factors used in preparing the estimates?	Section 5.3
4.5.5c		Are load forecasts broken down to at least the Zone Substation level and do they cover the whole of the planning period?	Sections 5.3 and 5.4
4.5.5c		Is there any discussion of the impact of uncertain but substantial individual projects or developments? Is the extent to which these uncertain load developments are included in the forecast clear?	Section 5.3
4.5.5c		Does the load forecast take into account the impact of any embedded generation or anticipated levels of distributed generation within the network?	Section 5.3
4.5.5c		Does the load forecast take into account the impact of any demand management initiatives?	Section 5.3
4.5.5c		Does the AMP identify anticipated network or equipment constraints due to forecast load growth during the planning period?	Section 5.4
4.5.5d	d) policies on distributed generation;	Does the AMP describe the policies of the EDB in relation to	Section 5.5

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: As increasing number of owners of small generators seek connection to distribution networks, distributed generation is anticipated to have an increasingly important influence on network operation and design. AMPs should describe the policies of an EDB's in relation to the connection of embedded generation. The impact of such generation on network development plans should be stated.	the connection of distributed generation?	
4.5.5d		Does the AMP discuss the impact of distributed generation on the EDB's network development plans?	Section 5.3
4.5.5e	e) policies on non-network solutions; *Explanation: Economically feasible and practical alternatives to conventional network augmentation should be discussed in this section. These are typically approaches that would reduce network demand and/or improve asset utilisation. This section should also include discussion on the potential for distributed generation or other non-network solutions to address network problems or constraints.*	Does the AMP discuss the manner in which the EDB seeks to identify and pursue economically feasible and practical alternatives to conventional network augmentation in addressing network constraints?	Section 5.5
4.5.5e		Does the AMP discuss the potential for distributed generation or other non-network solutions to address identified network problems or constraints?	Section 5.5
4.5.5f	f) analysis of the network development options available and details of the decisions made to satisfy and meet target levels of service; and	Does the AMP include an analysis of the network development options available and details of the decisions made to satisfy and meet target levels of service?	Sections 5.7 through to 5.22 and 5.24
4.5.5g	g) a description and identification of the network development programme (including distributed generation and non-network solutions) and actions to be taken, including associated expenditure projections. *Explanation: The network development plan should include:* *(i) a detailed description of the projects currently underway or planned to start in the next twelve months;* *(ii) a summary description of the projects planned for the next four years; and*	Does the AMP include : a detailed description of the projects currently underway or planned to start in the next twelve months;	Sections 5.7 through to 5.22 and 5.24
4.5.5g		a summary description of the projects planned for the next four years; and	Sections 5.7 through to 5.22 and 5.24

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
4.5.5g	*(iii) a high level description of the projects being considered for the remainder of the AMP planning period.* *For projects where decisions have been made, the reasons for choosing the selected option should be stated. For other projects planned to start in the next five years, alternative options should be discussed, including the potential for non-network approaches to be more cost effective than network augmentations.* *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A. Capital budgets should be broken down sufficiently to allow an understanding of expenditure on all the main types of development projects. Overhead to underground conversion projects should be separately indicated. Renewal and refurbishment projects should be included in the capital budget, although they are considered maintenance related works. The cost of major development projects should be separately identified in the capital budget.* *Minor capital works, or works related to whole categories of assets that have not been previously identified, may be discussed and budgeted in aggregate.*	a high level description of the projects being considered for the remainder of the planning period?	Sections 5.7 through to 5.22 and 5.24
4.5.5g		Does the AMP discuss the reasons for choosing the selected option for those major network development projects for which decisions have been made?	Sections 5.7 through to 5.22 and 5.24
4.5.5g		For other projects that are planned to start in the next five years, does the AMP discuss alternative options, including the potential for non-network alternatives to be more cost effective than network augmentations?	Sections 5.7 through to 5.22 and 5.24
4.5.5g		Does the AMP include a capex forecast, broken down sufficiently to allow an understanding of expenditure on all main types of development projects?	Section 5.25
4.5.6a	Disclosed AMPs must include a detailed description of lifecycle asset management plans, including: a) a description of maintenance planning criteria and assumptions; *Explanation: The key drivers for maintenance planning should be described.*	Does the AMP include a description of the EDB's maintenance planning criteria and assumptions?	Sections 6.1 and 6.2
4.5.6b	b) a description and identification of routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category, including associated expenditure projections; *Explanation: The approach to inspecting and maintaining all asset*	Does the AMP provide a description and identification of routine and preventive inspection and maintenance policies, programmes, and	Sections 6.2 and 6.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	management categories should be described, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done. *Systemic problems identified with any particular asset type should be highlighted and the actions to address these should be discussed.* *Budgets for maintenance activities broken down by asset category should be provided for the whole AMP period.*	actions to be taken for each asset category, including associated expenditure projections?	
4.5.6b		Does the AMP describe the process by which defects identified by its inspection and condition monitoring programme are rectified?	Sections 6.2 and 6.3
4.5.6b		Does the AMP highlight systemic problems for particular asset types and the actions being taken to address these?	Section 6.3
4.5.6b		Does the AMP provide forecasts for routine maintenance activities, broken down by asset category, for the whole planning period?	Sections 6.2 and 6.3
4.5.6c	c) a description of asset renewal and refurbishment policies;	Does the AMP provide a description of the EDB's asset renewal and refurbishment policies, including the basis on which refurbishment or renewal decisions are made?	Sections 6.1 and 6.3
4.5.6d	d) a description and identification of renewal or refurbishment programmes or actions to be taken for each asset category, including associated expenditure projections; and *Explanation: Asset renewal and refurbishment should be separately discussed, - although these are capex items they are not network development related and are therefore classed under maintenance. The process for deciding when and whether asset should be replaced or refurbished should be explained, as well as the factors on which these decisions are based.* *The discussion of renewal and refurbishment projects should include:*	Does the AMP discuss the planned asset renewal and refurbishment programmes for each asset category including:	Section 6.3
4.5.6di		- a detailed description of the projects currently underway and planned for the next twelve months;	Section 6.3
4.5.6dii		- a summary description of the projects planned for the next	Section 6.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	(i) a detailed description of the projects currently underway or planned for the next twelve months; *(ii) a summary description of the projects planned for the next four years; and* *(iii) a high level description of other work being considered for the remainder of the AMP planning period.* *The budget for renewal or refurbishment should be included as part of the capital budget.* *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A.*	four years; and	
4.5.6diii		- a high level description of the other work being considered for the remainder of the planning period?	Section 6.3
4.5.6e **7(2)a**[11]	e) asset replacement and renewal expenditure (which must be separately identified in the capital budget). *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A.*	Does the AMP include a forecast for renewal and refurbishments, broken down by major asset category, and covering the whole of the planning period?	Sections 6.7 and 9.4
		Does the AMP include details of the EDB's risks policies and assessment and mitigation practices including:	
4.5.7a	Disclosed AMPs must include details of risk policies, assessment, and mitigation, including: a) methods, details, and conclusions of risk analysis; and b) details of emergency response and contingency plans. *Explanation: Asset risk management forms a component of an EDB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the EDB identifies and assesses asset related risks and describe the main risks thus identified. The focus should be on credible low-probability, high-impact risks and how they will be managed.* *Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.*	- methods, details and conclusions of risk analysis;	Sections 8.1, 8.2 and 8.3
4.5.7		- the main risks identified;	Section 8.3
4.5.7b		- details of emergency response and contingency plans?	Sections 8.4 and 8.5
4.5.7		Does the AMP identify specific development projects or maintenance programmes with the objective of managing risk? Are these projects discussed and linked back to the development plan or maintenance programmes?	Section 8.3
4.5.8	Disclosed AMPs must include details of performance measurement, evaluation, and improvement, including:	Is the actual capex for the previous year compared with	Section 9.4

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	Explanation: A key outcome of an AMP is the identification of significant asset performance gaps that need to be addressed, or to adjust service level and asset performance targets to more appropriate levels. a) a review of progress against plan, both physical and financial; *Explanation: Actual capex should be compared against that planned in the previous AMP and any significant differences discussed. The progress of development projects against plan should be assessed and reasons for substantial variances highlighted, along with any significant construction or other problems experienced.* *Actual maintenance expenditure should be compared against that planned in the previous AMP and reasons for significant differences discussed. Progress against maintenance initiatives and programmes should be assessed and discussed and the effectiveness of these programmes noted.* b) an evaluation and comparison of actual performance against targeted performance objectives; and *Explanation: Service level and asset performance measurement should be carried out for all the targets discussed under the Service Levels section of the AMP. A comparison of actual against target performance for the year preceding the AMP should be provided, with an explanation for any significant variances.*	that presented in the previous AMP and are significant differences discussed?	
4.5.8		Is the progress of development projects against plan (as presented in the previous AMP) assessed and are the reasons for substantial variances highlighted? Is any construction or other problems experienced discussed?	Section 5.25
4.5.8		Is the actual maintenance expenditure compared with that planned in the previous AMP and the reasons for significant differences discussed?	Section 9.4
4.5.8		Is progress against maintenance initiatives and programmes assessed and discussed and is the effectiveness of these programmes noted?	Section 6
4.5.8		Is the measured service level and asset performance for the previous year presented for all the targets discussed under the Service Levels section of the AMP?	Sections 4.1 and 4.2
4.5.8		Is there a comparison between actual and target performance for the preceding year with an explanation for any significant variances?	Sections 4.1 and 4.2
4.5.8c	c) a gap analysis and identification of improvement initiatives. *Explanation: Where significant gaps between targeted and actual*	Does the AMP identify significant gaps between targeted and actual performance. If so, does	Sections 4.1 and 4.2

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	performance exist, the action to be taken to address the situation (if not caused by one-off factors) should be described. *It is good practice to also review the overall quality of asset management and planning processes and the AMP itself, and to discuss any initiatives for improvement.*	it describe the action to be taken to address the situation (if not caused by one-off factors)?	
4.5.8c		Does the AMP review the overall quality of asset management and planning within the EDB and discuss any initiatives for improvement?	Section 1.14
4.5.9a	Disclosed AMPs must include: a) forecasts of capital and operating expenditure for the minimum ten year asset management planning period; and b) reconciliations of actual expenditure against forecasts for the most recent financial year for which data is available. *Explanation: Expenditure forecasts and reconciliations shall be prepared in accordance with Appendix A. For the avoidance of doubt, these include forecast expenditure required under subclauses 4.5.5(g), 4.5.6(d) and 4.5.6(e). Sections A and B of the Appendix A report for the Financial year ending 31 March 2008 or 31 March 2009 need include only:* a. the "Actual for Current Financial Year" for the line items "Subtotal – Capex on Asset Management", "Subtotal – Opex on Asset Management" and "Total Direct Expenditure on the Distribution Network"; and b. in the case of the Appendix A report for the Financial year ending 31 March 2009, all information (including all line items) for all of the forecast years specified in part A of Appendix A. It should be noted that asset management expenditure forecasts, *for the first 5 years of the plan,* derived from the most recent AMP, are required to be disclosed with other financial statements (i.e. Report AM1, Schedule 12 of the Distribution Disclosure Requirements). This report is required to be audited, in accordance with Distribution Disclosure Requirement 10, which refers to Distribution Disclosure Requirement 7(5).	Does the AMP include: a) forecasts of capital and operating expenditure for the minimum ten year asset management planning period	Section 9.4
4.5.9b		b) reconciliations of actual expenditure against forecasts for the most recent financial year for which data is available.	Section 9.4
7.2	In any case where prospective information is required by subclause (1) to be Publicly disclosed the Distribution business must also Publicly disclose the following (as at the date of the asset management plan):	Does the AMP identify all significant assumptions that are considered to have a material	Section 1.3

Handbook Clause	Handbook Requirements / Disclosure Requirements	Interpretation	AMP Reference
	(a) all significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers, and quantified where possible; (b) a description of changes proposed where the information is not based on the Distribution business's existing business; (c) the basis on which significant assumptions have been prepared, including the principal sources of information from which they have been derived; (d) the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures; and (e) the assumptions made in relation to these sources of uncertainty and the potential effect of the uncertainty on the prospective information.	impact on forecast expenditure (capital or operating) for the planning period?	
7.2		Are the significant assumptions presented and discussed in a manner that makes their source(s) and impact(s) understandable to electricity consumers?	Section 1.3
7.2		Does the AMP identify assumptions that have been made in relation to the sources of uncertainty?	Section 1.3

Electricity
Asset Management Plan
2011 – 2021

Assets Covered by this Plan – Section 2

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

2. Assets Covered by this Plan

2.1 Distribution Area

The Vector network is centred on the Auckland isthmus and supplies north to Mangawhai Heads (Northern network) and south to Franklin (Southern network). The map in Figure 2-1 shows the network boundaries, with Northpower in the north and Counties Power in the south. It also shows the boundary of the new wards administered by the Auckland Council. In addition, Vector supplies a large customer at Lichfield which is a stand-alone supply.

Figure 2-1 : Vector electricity supply area

While Vector operates its network in Auckland as a single unit, there are some legacy differences associated with previous ownership structures and it is convenient to separately describe the Southern and Northern regions.

2.1.1 Northern Region

The Northern region covers those areas administered by the previous North Shore City Council, Waitakere City Council and Rodney District Council. The Northern region consists of residential, commercial and industrial developments in the urban areas, and residential and farming communities in the rural areas.

Most commercial and industrial developments are in Takapuna, the Albany basin, Glenfield, Henderson and Te Atatu. New regional commercial centres are being developed as part of the development in growth areas such as Westgate, Orewa/Silverdale and Whenuapai. There are few high density, high rise developments typical of major central business districts (CBDs) but the trend is evolving.

Areas north of the Whangaparaoa Peninsula and west of Henderson and Te Atatu are predominantly rural apart from scattered small townships. Zoning in these areas is largely for farming or conservation use.

The eastern and south-eastern parts of Waitakere City and the southern parts of North Shore City consist of medium density urban dwellings that are part of metropolitan Auckland.

The historical development of the electrical network has centred around coastal townships that have in time expanded with population growth. With New Zealand Transport Agency's expansion of the motorway network north of the Albany basin, it is expected that urban development will continue to move northwards.

2.1.2 Southern Region

The Southern region covers areas administered by the previous Auckland City Council, Manukau City Council and Papakura District Council. The Southern region consists of residential, commercial and industrial developments in the urban areas, and residential and farming communities in the rural areas.

Most commercial and industrial developments are in Penrose, Newmarket, St Lukes, Mt Wellington, East Tamaki, Mangere, Takanini and Onehunga. Auckland also has the largest CBD area in New Zealand which accommodates the main commercial centre of the country.

There is also a significant amount of in-fill commercial and residential developments scattered throughout the region. Development density in the Auckland tends to be higher than in other parts of the country. This includes high rise residential apartments in the CBD, high density town house developments in suburban areas, industrial parks etc.

2.1.3 Major Customer Sites on the Vector Network

Vector has a number of large customer sites at various locations in its network. The following are those customer sites with individual demand above 5MVA, which are considered to have a significant impact on network operations and asset management:

- Fonterra cheese factory at Lichfield;
- Auckland International Airport;
- Mangere Waste Water Treatment Plant;
- Owens Illinois;

- Fisher & Paykel appliance factory at East Tamaki;
- Pacific Steel;
- Ports of Auckland;
- Laminex Penrose;
- Coca Cola Amatil (NZ);
- Devonport Naval Base;
- Carter Holt Harvey, Penrose;
- Masport Limited; and
- Westfield NZ Limited – Albany, St Lukes, Manukau.

2.2 Load Characteristics

Traditionally, residential load has a winter evening peaking characteristic. This is ideal from an asset rating perspective, as the cool temperature and (usually) moist ground condition increase equipment ratings. However, we anticipate a strong trend towards installing new residential appliances such as heat pumps (refer Section 3), with indications that some winter peaking residential feeders and substations will move towards summer daytime peaking. (The Auckland CBD and other air conditioned office blocks already exhibit summer peaking characteristics.) Presently the winter residential peak load is about twice the summer peak load but it is expected this gap will close over the next ten years. The typical daily load profiles for residential and commercial loads for summer and winter are illustrated in Figure 2-2 to Figure 2-5 below. The demands are expressed as a percentage of the peak demand. It can be seen that the residential load has peaks in the mornings and evenings whereas the commercial load is consistent throughout the day. During weekends, the commercial load, due to office blocks not being occupied, is much lower, apart from large shopping centres that operate seven days a week.

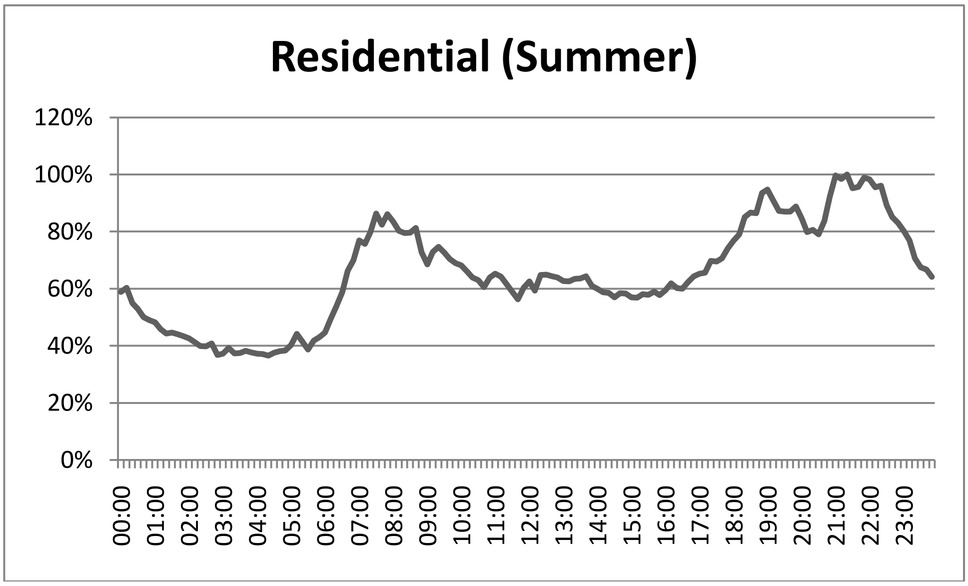


Figure 2-2 : Typical summer load profile for residential customers

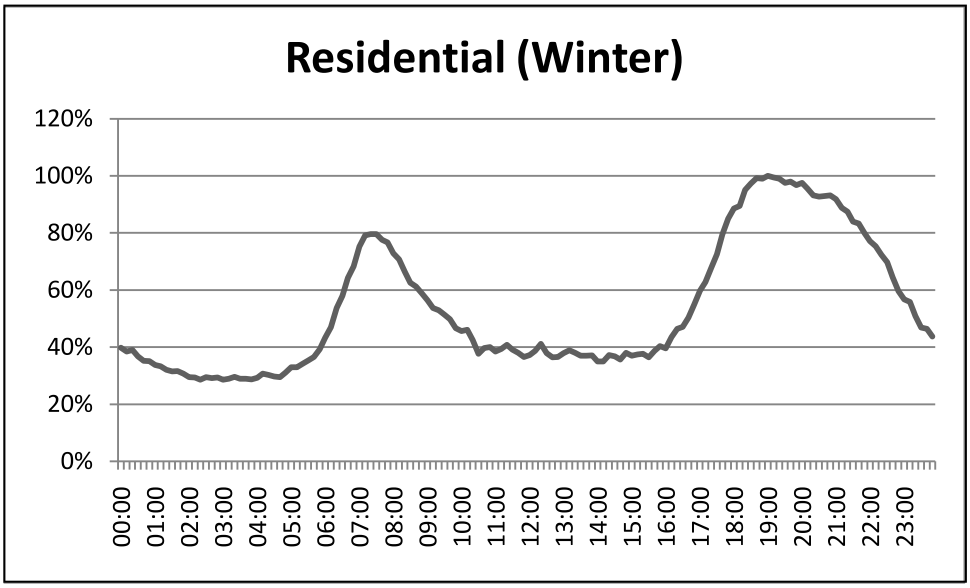


Figure 2-3 : Typical winter load profile for residential customers

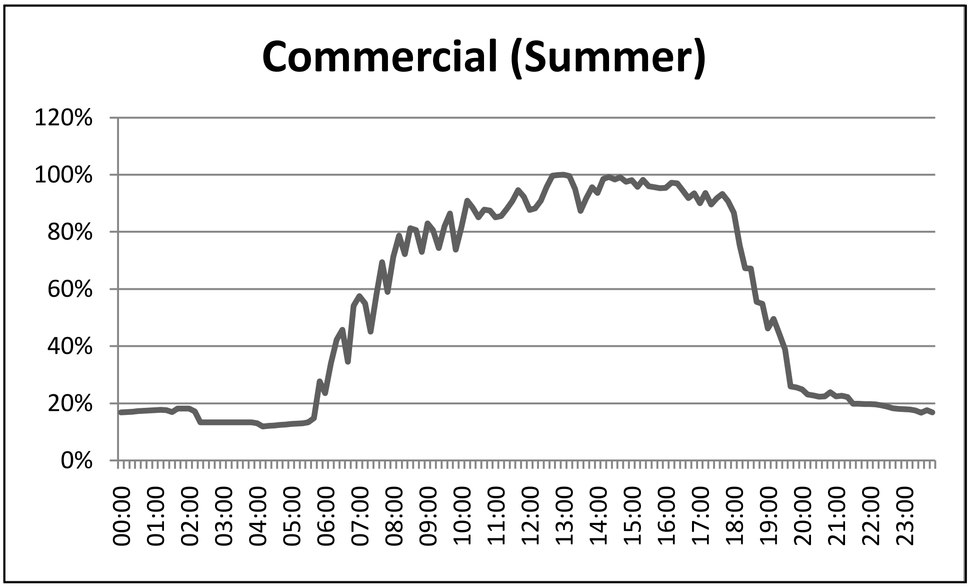


Figure 2-4 : Typical summer load profile for commercial customers

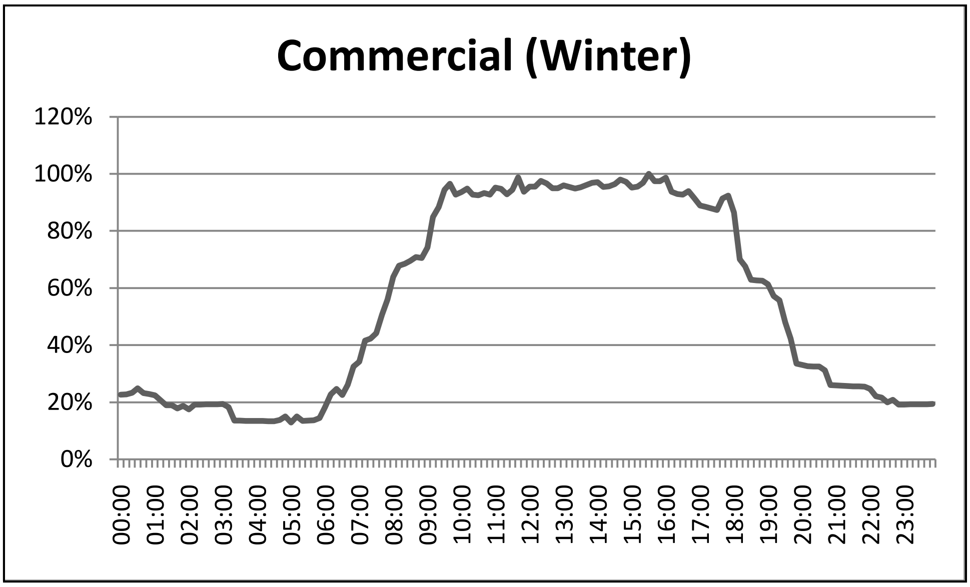


Figure 2-5 : Typical winter load profile for commercial customers

A measure of load diversity is achieved with residential customers providing peaks in the morning and early evening, with the commercial load filling in the trough between these peaks. Clearly the mix of customer types on a feeder influences the size and duration of the peaks.

Demand curves for industrial customers are far more variable – conforming closely to the nature of the customer's business. A typical industrial load curve is, therefore, not a meaningful concept.

The half-hour peak demand on the regional networks and the energy delivered for the past three years are listed in Table 2-1. (The individual demand forecasts for zone substations on Vector's network are detailed in Section 5.4.)

Regulatory Year	Northern Peak Demand (MW)	Southern Peak Demand (MW)	Combined Peak Demand (MW)	Northern Energy Delivered (GWh)	Southern Energy Delivered (GWh)
2007/08	596	1134	1676	2565	5638
2008/09	603	1111	1711	2556	5688
2009/10	613	1162	1775	2598	5713

Table 2-1 : Half-hour peak demand and energy delivered on the regional networks

The values reported above are the coincidental peak demands of all Grid Exit Points (GXPs) delivering supply to Vector, as well as major embedded generation.

In accordance with the Commerce Commission's Electricity Information Disclosure Requirements 2004, Lichfield is included in the Northern region in the above table.

Embedded Generation

The major embedded generators on the network (capacity > 1MW) are at Greenmount, Whitford, Redvale and Rosedale landfill sites, Mangere Waste Treatment Plants, and at Auckland Hospital, but excludes Southdown which is a notionally embedded generator (connected at 220kV to the Transpower Otahuhu to Henderson line, with no direct physical connection to the Vector network). Over time, when gas production at landfill sites becomes depleted, the gas generators will be relocated and feeder reinforcement will have to be considered to maintain security of supply in the local areas. The generation capacities of embedded generators will be closely monitored to ensure sufficient forewarning of reinforcements.

2.3 Network Configuration

The overall architecture of the Vector network is shown in Figure 2-6.

Vector receives electricity supply from the national grid at thirteen Grid Exit Points (GXPs), owned by Transpower. The Vector network is made up of three main component networks: sub-transmission (110kV, 33kV and 22kV), medium voltage distribution (22kV and 11kV) and low voltage distribution (400/230V).

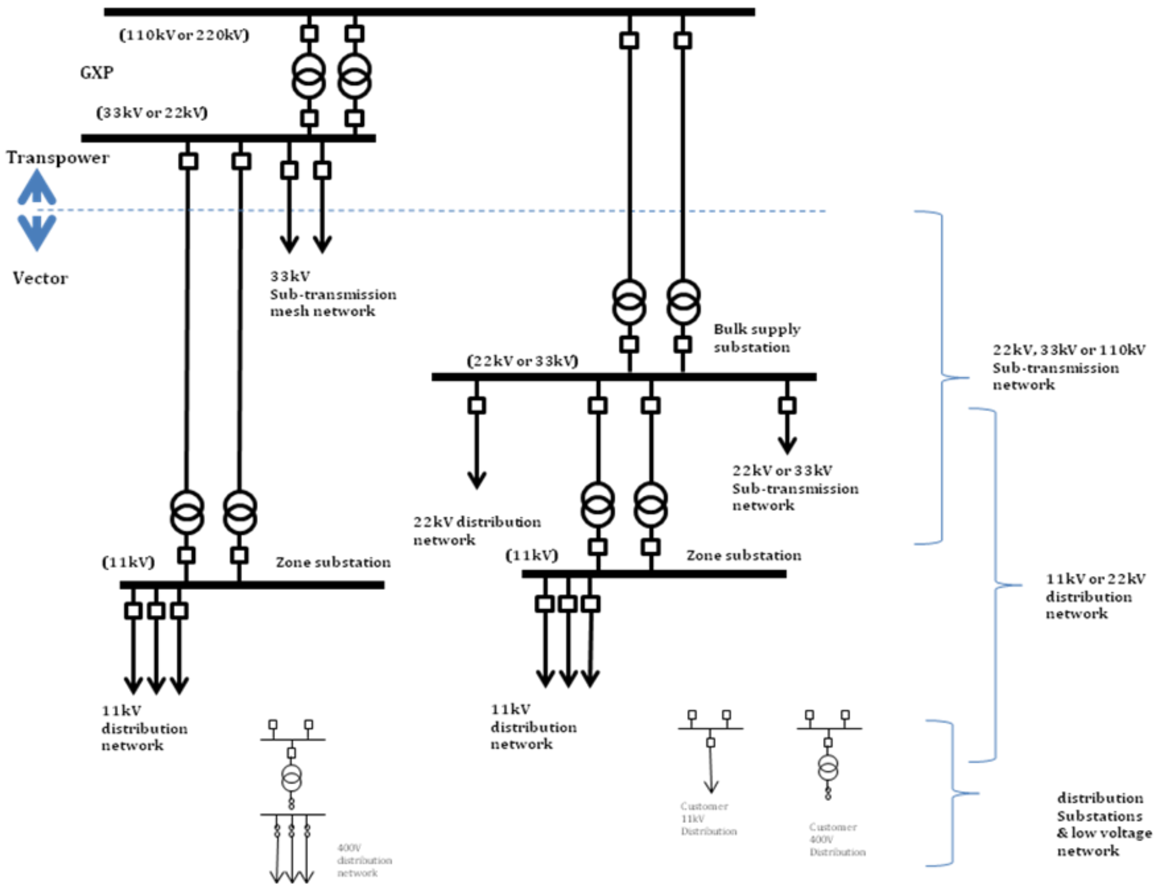


Figure 2-6 : Schematic of Vector's network

2.3.1 The Transmission Grid around Auckland

The electricity supply into Auckland from generation in the central North Island and the South Island is provided by six 220kV circuits and two 110kV circuits. All eight circuits terminate onto the 220kV busbar and 110kV busbar at Otahuhu GXP. From Otahuhu GXP, two 220kV circuits and four 110kV circuits have been installed to supply the demand north of the Auckland Isthmus. Another two 220kV circuits and four 110kV circuits have been installed to supply the Auckland Isthmus.

Vector takes supply from the national transmission grid at 12 GXPs to supply its sub-transmission network. A thirteenth GXP (Lichfield GXP) is dedicated to the supply of the Fonterra Cheese Factory at Lichfield in Tokoroa. Subtransmission supply is taken at 110kV, 33kV and 22kV. Vector has also established five internal bulk supply substations to supply its sub-transmission networks in Auckland, that are a long distance from the grid.

Table 2-2 to Table 2-5 show the winter and summer peak demands at GXPs and bulk supply substations. The tables also show the installed capacity and firm capacity at each of these supply points. For completeness, the tables also show the GXP at Lichfield in Tokoroa where Vector takes supply to supply the Fonterra cheese factory.

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity[1] (MVA)	2010 Winter Peak Demand (MVA)
Mangere	110kV			55
Mangere	33kV	2x120	118	95
Otahuhu	22Kv	2x50	59	56
Pakuranga	33kV	2x120	136	130
Penrose	110kV			191
Penrose[2]	33kV	2x160 + 1x200	428	315
Penrose	22kV	3x45	90	56
Roskill	110kV			54
Roskill	22kV	2x70 + 1x50	141	104
Takanini	33kV	2x150	123	113
Wiri	33kV	2x100	107	75
Albany	110kV			130
Albany	33kV	1x120 + 2x100	234	151
Henderson	33kV	2x120	135	95
Hepburn	33kV	1x85 + 2x120	245	117
Silverdale	33kV	1x120 + 1x100	109	71
Wellsford	33kV	2x30	31	30
Lichfield	110kV			8

Table 2-2 : Grid Exit points for Auckland and Lichfield winter loads

[1] Firm capacities supplied by Transpower.

[2] Penrose 33kV busbar supplies Penrose 22kV load.

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)	2010 Summer Peak Demand (MVA)
Mangere	110kV			53
Mangere	33kV	2x120	118	84
Otahuhu	22Kv	2x50	59	47
Pakuranga	33kV	2x120	136	104
Penrose	110kV			216
Penrose	33kV	2x160 + 1x200	406	275
Penrose	22kV	3x45	90	53
Roskill	110kV			36
Roskill	22kV	2x70 + 1x50	141	65
Takanini	33kV	2x150	123	87
Wiri	33kV	2x100	107	72
Albany	110kV			82
Albany	33kV	3x120 + 2x100	234	109
Henderson	33kV	2x120	135	76
Hepburn	33kV	1x85 + 2x120	239	87
Silverdale	33kV	1x120 + 1x100	109	46
Wellsford	33kV	2x30	31	21
Lichfield	110kV			8

Table 2-3 : Grid Exit points for Auckland and Lichfield summer loads

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2010 Winter Peak Demand (MVA)
Kingsland	22kV	2x60	60	55.7
Liverpool	22kV	2x75+1x60	135	106.5
Quay	22kV	1x60+2x50	60	31.8
Hobson	22kV	2x40	40	42.9
Wairau Road	33kV	3x80	160	130.0
Pacific Steel	33kV	70+40	40	54.9
Lichfield	11kV	2x20	24	8.5

Table 2-4 : Bulk Supply Substations for Auckland and Lichfield winter loads

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	Firm Capacity (MVA)	2010 Summer Peak Demand (MVA)
Kingsland	22kV	2x60	60	36.2
Liverpool	22kV	2x75+1x60	135	104.6
Quay	22kV	1x60+2x50	60	36.6
Hobson	22kV	2x40	40	35.6
Wairau Road	33kV	3x80	160	82.0
Pacific Steel	33kV	70+40	40	52.8
Lichfield	11kV	2x20	24	8.4

Table 2-5 : Bulk Supply Substations for Auckland and Lichfield summer loads

The following map in Figure 2-7 shows the locations of the GXP and the main 110kV and 220kV lines supplying into and across Auckland.

Figure 2-7 : Locations of GXPs and major transmission lines supplying Vector

2.3.2 Sub-transmission network

The sub-transmission networks for the Northern and Southern regions have been developed differently. The Northern network has a mixture of interconnected 33kV ring and radial circuits (largely overhead lines) connected to the Transpower GXPs. It is a common practice to have 33kV switches at zone substations. This has allowed some interconnection between GXPs.

The Southern region is largely radial circuits supplying two to three transformer zone substations. These are largely supplied by underground cables. Sub-transmission voltages range from 110kV in the Auckland CBD and supply to Kingsland, through to 33kV and 22kV elsewhere in the Southern region.

Capacities of existing zone substations in the Southern region are larger (typically two or three 20MVA transformers at each substation) whereas about half of the Northern region's zone substations are single transformer substations (with transformer size ranging from 5MVA to 20MVA). Since 2005, new transformers purchased for urban zone substations are rated at 20MVA whereas those for rural areas are 10MVA.

Typically zone substations in the Northern region are equipped with a 33kV switchboard (or outdoor busbar), an 11kV switchboard and transformers. Zone substations in the Southern region typically do not have 33kV (or 22kV) switchboards except for those that are established as part of a bulk in-feed substation or switching station.

A description of the development plan for the sub-transmission network and the zone substations is given in Section 5 of this plan.

Table 2-6 lists Vector's zone substations as at the beginning of 2011 together with their installed capacities, n-1 firm capacities (if applicable), the 2010 winter peak demand, the substation security level and distribution backstop capacities.

Zone substation	Supply voltage	Installed Capacity[3] (MVA)	Substation n-1 Capacity[4] (MVA)	2010 Winter Peak Demand (MVA)	N-X security	Feeder backstop capacity[5] (MVA)
Atkinson Road	33kV	2x20	24	18.2	N-1	17.3
Auckland Airport	33kV	2x25	25	16.5	N-1	10
Avondale	22kV	2x20	24	27.4	N	22.2
Bairds	22kV	2x20	24	22.6	N-1	22.2
Balmain	33kV	1x12.5	0	8.7	N	8.5
Balmoral	22kV	2x12	14.3	15	N	11.2
Belmont	33kV	2x12.5	14	13	N-1	5.4
Birkdale	33kV	2x12.5	15.2	22.3	N	15
Brickworks	33kV	1x12.5	0	7.3	N	8.7
Browns Bay	33kV	2x12.5	14	14.9	N	15.1
Bush Road	33kV	2x24	23.8	24.9	N	13.1
Carbine	33kV	2x20	22.5	24.2	N	8.4

[3] Transformer nameplate ratings applied.

[4] Substation cyclic capacity (at sub-transmission level) after losing the component with the highest capacity.

[5] Total backstop capacity available from the 11kV network for 11kV zone substations, and 22kV express feeders for CDB substations 22kV load.

Zone substation	Supply voltage	Installed Capacity[3] (MVA)	Substation n-1 Capacity[4] (MVA)	2010 Winter Peak Demand (MVA)	N-X security	Feeder backstop capacity[5] (MVA)
Chevalier	22kV	1x18 + 1x20	17.1	17.6	N	17.9
Clendon	33kV	2x20	24	15.4	N-1	15.1
Clevedon	33kV	1x5	0	3.5	N	3.5
Coatsville	33kV	1x12.5	0	9.5	N	9
Drive	33kV	2x20	24	29.9	N	20.6
East Coast Road	33kV	1x24	0	16.5	N	13.3
East Tamaki	33kV	2x20	24	16.1	N-1	7.7
Forrest Hill	33kV	1x12.5 +1x20	16	16.6	N	13.4
Freemans Bay	22kV	1x18 + 1x20	21.6	17.9	N-1	15.2
Glen Innes	22kV	2x12	12.2	13.6	N	12.6
Greenhithe	33kV	1x20	0	12.4	N	12.6
Greenmount	33kV	3x20	48	38.2	N-1	26.8
Gulf Harbour	33kV	1x20	0	6.9	N	6.9
Hans	33kV	2x20	24	23.9	N-1	9.7
Hauraki	33kV	1x12.5	0	8.1	N	8.3
Helensville	33kV	2x7.5	9	13.2	N	7.5
Henderson Valley	33kV	2x12.5	15.2	22.8	N	11.4
Highbrook[6]	22kV	-	0	4.5	N	23
Highbury	33kV	1x12.5	0	10.7	N	7.4
Hillcrest	33kV	2x24	23.8	23.4	N-1	22.7
Hillsborough[7]	22kV	1x20	0	0	N	20.4
Hobson 22kV[8]	110kV	2x40	40	36.9	N-1	120
Hobson 110/11kV[9]	110kV	2x25	25	26.7	N-1	15.9
Hobson 22/11kV[10]	22kV	2x15	15	14.1	N-1	23.3
Hobsonville	33kV	2x12.5	16	18.6	N	9.2
Hospital	22kV	1x10	0	6.2	N	8
Howick	33kV	3x20	46	37.2	N-1	11.7
James Street	33kV	2x12.5	16	19.2	N	14.3
Keeling Road	33kV	1x24	0	9.7	N	9

[6] Highbrook is a 22kV switching station feeding the 22kV network supplying the Highbrook Industrial Park.

[7] Substation commissioned after the winter peak.

[8] The Hobson 11kV busbar is supplied by 2x22/11kV 15MVA transformers and 2x110/22/11kV (25MVA) transformers.

[9] The Hobson 11kV busbar is supplied by 2x22/11kV 15MVA transformers and 2x110/22/11kV (25MVA) transformers.

[10] The Hobson 22kV busbar is supplied by 2x110/22/11kV (40MVA) transformers

Zone substation	Supply voltage	Installed Capacity[3] (MVA)	Substation n-1 Capacity[4] (MVA)	2010 Winter Peak Demand (MVA)	N-X security	Feeder backstop capacity[5] (MVA)
Kingsland	22kV	2x20	24	22.7	N-1	14.4
Laingholm	33kV	2x7.5	8.4	8.7	N	5
Liverpool	22kV	3x20	48	44.3	N-1	24.4
Liverpool 22kV	110kV	3x60	120	104.6	N-1	86
Mangere Central	33kV	2x20	24	24.5	N	12.7
Mangere East	33kV	2x20	24	25.7	N	18.1
Mangere West	33kV	2x30	36	16.4	N-1	3
Manly	33kV	2x12.5	14	14.6	N	12.5
Manukau	33kV	3x20	48	28.9	N-1	20.9
Manurewa	33kV	3x20	46.9	50.2	N	25
Maraetai	33kV	2x15	15.2	6.7	N-1	3.9
McKinnon	33kV	1x24 +1x20	23.8	17.1	N-1	8.8
Mcleod Road	33kV	1x12.5	0	12.2	N	10.7
McNab	33kV	3x20	48	43.1	N-1	22
Milford	33kV	1x12.5	0	8.8	N	8
Mt Albert	22kV	1x12	0	9.5	N	10.1
Mt Wellington	33kV	2x20	24	23	N-1	21
New Lynn	33kV	2x12.5	14	14.9	N	12.7
Newmarket	33kV	3x20	48	36.3	N-1	29.9
Newton	22kV	2x16	19.2	18.7	N-1	17.8
Ngataringa Bay	33kV	1x12.5	0	8.5	N	4.2
Northcote	33kV	1x16	0	8.5	N	3.7
Onehunga	22kV	2x15	14.8	20	N	19.7
Orakei	33kV	2x18	21.6	24.2	N	13.3
Oratia	33kV	1x10	0	5.2	N	5.4
Orewa	33kV	2x20	15.2	13.7	N-1	7.6
Otara	22kV	2x15+20	30.8	30.4	N-1	18.4
Pacific Steel	110kV	1x70 + 1x40	40	54.9	N	10
Pakuranga	33kV	2x20	24	23.6	N-1	9.9
Papakura	33kV	2x20	24	23.1	N-1	8.9
Parnell	22kV	2x12	12	9.7	N-1	12.1
Ponsonby	22kV	2x12	14.4	15.4	N	8.1
Quay	22kV	2x20	24	21.1	N-1	18.2
Quay 22kV	110kV	2x50 + 1x60	66	34	N-2	86
Ranui	33kV	1x20	0	5.7	N	5.9
Red Beach	33kV	1x20	0	12.3	N	11.6
Remuera	33kV	2x20	24	30.6	N	20.9
Riverhead	33kV	2x7.5	9	9.6	N	8.6

Zone substation	Supply voltage	Installed Capacity[3] (MVA)	Substation n-1 Capacity[4] (MVA)	2010 Winter Peak Demand (MVA)	N-X security	Feeder backstop capacity[5] (MVA)
Rockfield	33kV	2x20	24	18.3	N-1	20.1
Rosebank	33kV	2x21.5	25.8	22.1	N-1	7.4
Sabulite Road	33kV	2x12.5	14	18.6	N	15.4
Sandringham	22kV	2x20	24	20.5	N-1	26.9
Simpson Road	33kV	1x7.5	0	7.1	N	8.4
Snells Beach	33kV	1x7.5	0	6	N	3.3
South Howick	33kV	2x20	24	29.5	N	15.5
Spur Road	33kV	1x12.5	0	11	N	12.1
St Heliers	33kV	2x17.5	21	22.3	N	16.6
St Johns[11]	33kV	2x20	24	0	N-1	12.3
Sunset Road	33kV	2x12.5	14	18.2	N	12.7
Swanson	33kV	1x12.5	0	13.6	N	10.7
Sylvia Park	33kV	2x20	24	11	N-1	26.9
Takanini	33kV	2x15	18	18.2	N	15.3
Takapuna	33kV	1x24	0	9	N	8.5
Te Atatu	33kV	2x12.5	14	19.9	N	9.6
Te Papapa	33kV	2x20	24	23	N-1	9.5
Torbay	33kV	1x12.5	0	9.8	N	6.5
Triangle Road	33kV	2X10	12	19.4	N	14.7
Victoria	22kV	2x20	24	24.2	N	20.6
Waiake	33kV	1x12.5	0	9.4	N	8.1
Waiheke	33kV	2x12.5	15	9.3	N-1	2.7
Waikaukau	33kV	1x7.5	0	6.8	N	7
Waimauku	33kV	1x7.5	0	6.4	N	3.3
Wairau	33kV	2x12.5	16	15.9	N-1	16.4
Warkworth	33kV	3x7.5	18	16.8	N-1	16.5
Wellsford	33kV	2x7.5	9	7.3	N-1	3.8
Westfield	22kV	2x20+1x15	40.6	31	N-1	12.6
White Swan	22kV	3x15	34.7	30.6	N-1	18.4
Wiri	33kV	3x20	48	34	N-1	20.7
Woodford	33kV	1x12.5	0	10.4	N	11.5

Table 2-6 : Vector's zone substation loading and security

2.3.2.1 Outdoor versus Indoor Substations

All new zone substations have switchgear installed indoors.

[11] Substation commissioned after the winter peak.

Some older substations still have outdoor equipment. The condition of these outdoor 33kV switchyards is monitored and where economically or technically justifiable they are being replaced with indoor switchgear.

2.3.2.2 Undergrounding

The Northern region has a large percentage of overhead lines, particularly in the rural areas. The sub-transmission system in this region is largely constructed overhead. This makes the network much more vulnerable during strong winds and storms. On the other hand, the Southern region sub-transmission network is all underground except for the supply to Maraetai. This makes the sub-transmission network very secure from winds and storms, but vulnerable to dig-ins and ground movement.

Since the ownership of the Northern network changed to Vector in 2003, all new sub-transmission circuits have been installed underground except for the rural areas which will remain overhead. As at the end of March 2010, 90% of the sub-transmission network is underground in the Southern region and 27% in the Northern region. Overall, 59% of Vector's sub-transmission network is underground.

2.3.2.3 Vector Grouping[12]

Due to historical development, the power transformers supplying different parts of Vector's sub-transmission network are configured to different vector groups.[13] Using the grid (220kV and 110kV) as reference, the phase angles of the sub-transmission network in the different parts of the Vector network are shown in the vector diagrams in Figure 2-8 to Figure 2-10.

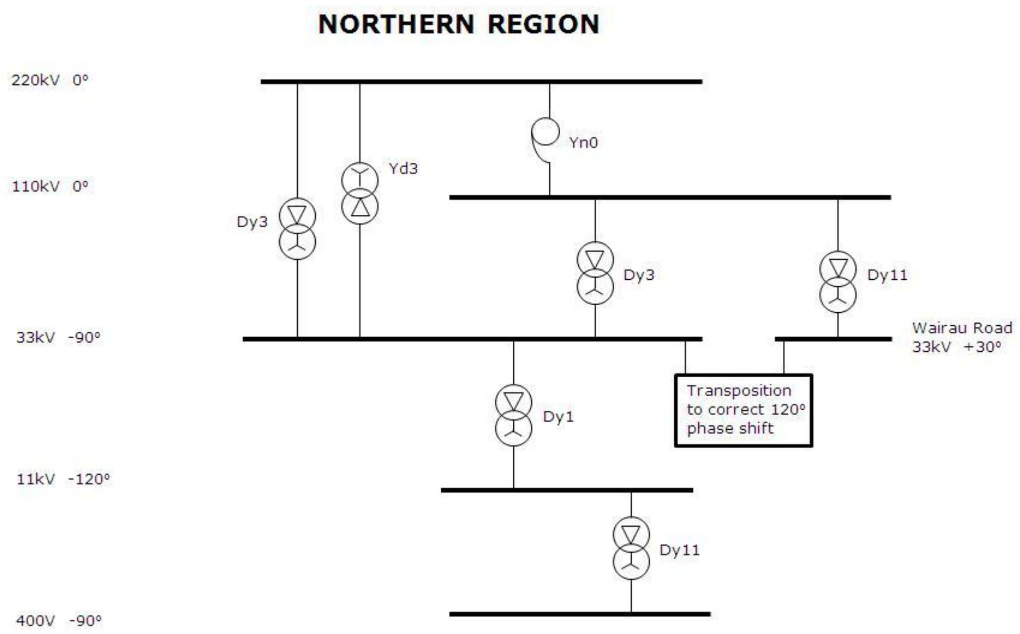


Figure 2-8 : Vector groups of transformers supplying the Northern region

---

[12] To avoid confusion, in this context the vector grouping refers to the internal winding configuration of a transformer and has nothing to do with Vector as a company or group.

[13] Ibid.

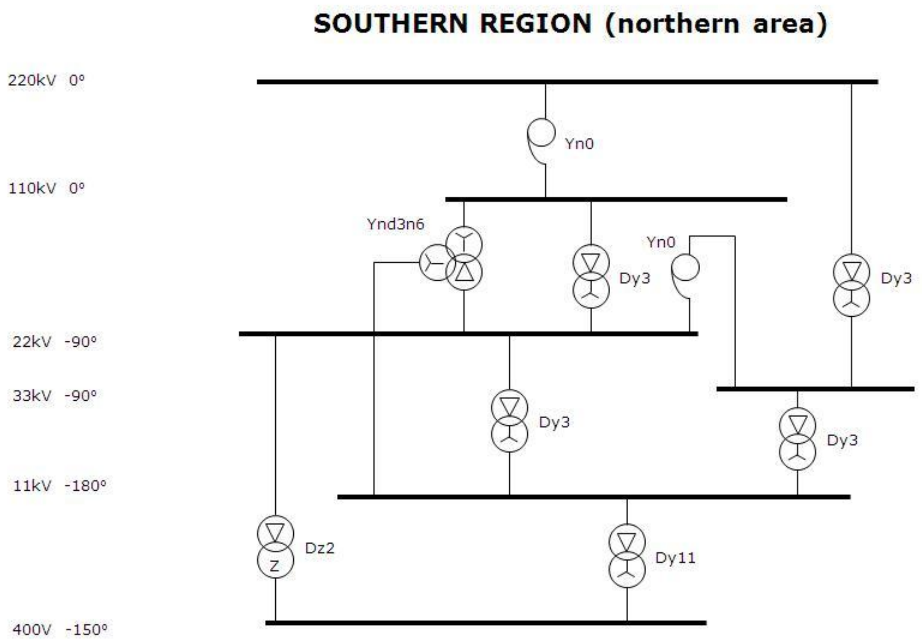


Figure 2-9 : Vector groups of transformers supplying the Southern region (northern area)

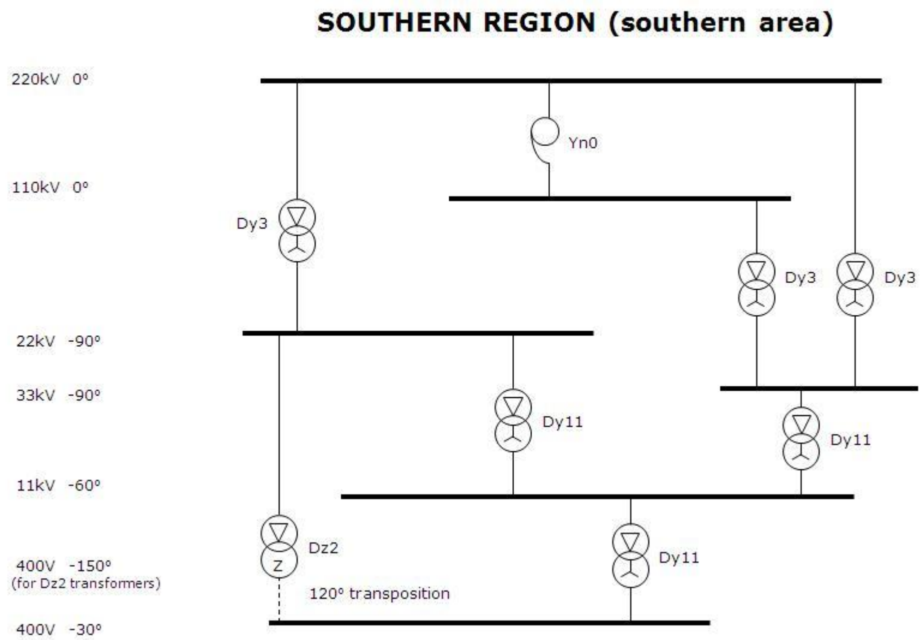


Figure 2-10 : Vector groups of transformers supplying the Southern region (southern area)

From the vector diagrams, it can be seen that the sub-transmission network in all regions are all in phase except at Wairau Road substation where the 110/33kV transformers are Dy11. Rotation of the 33kV feeders supplied by the Dy11 transformers by 120° before connecting to the network fed from other substations enable them to operate in parallel with the rest of the sub-transmission network. This rotation will be corrected when a new 220/33kV transformer and a new 33kV switchboard is commissioned (scheduled for 2013).

The 11kV network between the northern area and southern area of the Southern region is 120° out of phase. A rotation of 120° has already been made at the 11kV network supplied by the two areas to allow them to operate in parallel. The same applies to the 400V network. The phase angle between the 11kV network in the Northern region and Southern region is 60°. Phase correction between the two regions can only be made via a phase correction transformer. The 22kV/400V transformers in the Auckland CBD are Dz2 units to enable them to run in parallel with the existing LV network supplied from the 11kV network. The 22kV/400V transformers used at Highbrook development are Dz2 units. The 400V network is, therefore, 120° out of phase with the LV network supplied from neighbouring 11kV network and has to be rotated by 120° before parallel operation is feasible.

2.3.2.4 Prospective fault currents

Prospective fault currents at the various zone substation busbars were calculated using DigSilent Power Factory version 14.0 with the network configuration as at January 2010. The source fault levels were supplied by Transpower. Known significant embedded generation were included in the model.

The DigSilent Complete Methodology was used in the fault current calculation. This is a superposition method where load flows are performed to determine the pre-fault condition of the network such as the busbar voltage and tap changer positions. The winter demand forecasts provide in section 5.4 of this plan have been used for the load flow study.

Vector's 11kV circuit breakers have historically been specified to break fault currents of 13.1kA, although some individual circuit breakers purchased from certain manufacturers recently may have higher capabilities. It is essential to recognise the prospective fault currents when designing the fault ratings of equipment.

Table 2-7 summarises the prospective fault currents (expressed in kA) at the various zone substations with the 11kV bus sections at multi transformer substations closed.

	2011			2016			2021		
Substations	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Atkinson Road	8.6	7.4	9.6	8.6	7.5	9.6	8.6	7.5	9.6
Auckland Airport	10.7	9.3	10.7	10.8	9.4	10.7	11	9.5	10.8
Avondale	7.6	6.6	7.9	7.6	6.6	7.9	7.7	6.6	8
Bairds	8.6	7.5	9.1	8.7	7.5	9.2	8.7	7.5	9.2
Balmain	6.1	5.2	6.8	6.1	5.2	6.8	6	5.2	6.7
Balmoral	8.4	7.3	9	8.4	7.2	8.9	8.4	7.3	9
Belmont	10.4	9	11.9	10.4	8.9	11.9	10.4	8.9	11.9
Birkdale	10.5	9.1	12.1	10.5	9.1	12.1	10.5	9	12.1
Brickworks	6.5	5.6	7.1	6.5	5.6	7.1	6.5	5.6	7.1
BrownsBay	13.1	11.3	**14.4**	13.1	11.3	**14.4**	13.1	11.3	**14.4**

Substations	2011			2016			2021		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Bush Road	12.1	10.5	13	12.2	10.5	13	12.2	10.6	13.1
Carbine	8.1	7	8.3	8.1	7	8.3	8.3	7.2	8.6
Chevalier	5.3	4.6	5.1	5.3	4.6	5.1	5.3	4.6	5.1
Clendon	9.3	8	10.4	9.3	8	10.4	9.4	8.1	10.5
Clevedon	3.7	3.2	3.8	3.7	3.2	3.8	3.7	3.2	3.8
Coatsville	6.5	5.5	6.9	6.6	5.6	7	6.6	5.6	7
Drive	8.5	7.3	8.6	8.5	7.3	8.6	8.8	7.6	8.9
East Coast Road	6.6	5.7	7	6.6	5.7	7	6.6	5.7	7
East Tamaki	10.6	9.2	11.3	10.5	9.1	11.3	10.6	9.2	11.4
Forrest Hill	11.2	9.7	12.4	11.2	9.7	12.4	11.2	9.7	12.4
Freemans Bay	9.9	8.5	10.6	9.9	8.5	10.6	9.9	8.6	10.6
Glen Innes	7.5	6.5	8.2	7.5	6.5	8.2	7.7	6.7	8.5
Greenhithe	5.1	4.4	5.6	5.1	4.4	5.6	5.1	4.4	5.7
Greenmount	11.7	10.1	12.4	11.8	10.2	12.4	11.9	10.3	12.5
Gulf Harbour	5.3	4.6	5.9	5.3	4.6	5.9	5.3	4.6	5.8
Hans	8	6.9	8.3	8.1	7	8.4	8.2	7.1	8.4
Hauraki	6.2	5.4	6.7	6.3	5.4	6.8	6.3	5.5	6.9
Helensville	4.9	4.2	5.9	4.9	4.2	5.9	4.9	4.2	5.9
Henderson Valley	11.6	10	**13.3**	11.6	10	**13.3**	11.6	10	**13.3**
Highbrook	18.1	15.7	18.9	17.9	15.5	18.7	17.9	15.5	18.6
Highbury	5.9	5.1	6.6	5.9	5.1	6.5	5.9	5.1	6.5
Hillcrest	11	9.5	12.3	11	9.6	12.3	11	9.5	12.3
Hillsborough	4.5	3.9	4.7	4.5	3.9	4.7	4.6	3.9	4.8
Hobson 110/11kV	12	10.4	0.9	12	10.4	0.9	12	10.4	0.9
Hobson 22/11kV	7.1	6.1	7.5	7.2	6.2	7.6	7.2	6.2	7.5
Hobson 22kV distribution	17.9	15.3	13.5	17.9	15.5	13.5	18.1	15.7	13.4
Hobsonville	11.7	10.1	12.9	11.8	10.2	12.9	11.8	10.2	12.9
Hospital	4.7	4.1	5.1	4.8	4.1	5.1	4.8	4.1	5.1
Howick	11.8	10.2	12.4	11.8	10.2	12.5	11.8	10.2	12.5
James Street	10	8.6	11.7	10	8.6	11.7	10	8.7	11.7
Keeling Road	6.1	5.3	7.4	6.2	5.3	7.4	6.2	5.4	7.5
Kingsland	7.6	6.5	8.3	7.6	6.6	8.3	7.7	6.6	8.4
Kingsland 22kV	11.1	9.6	11.6	11.1	9.6	11.6	11.2	9.7	11.6
Laingholm	7.4	6.4	8.4	7.4	6.4	8.4	7.4	6.4	8.4
Liverpool 11kV	9	7.8	10	9.1	7.9	10.1	9.2	8	10.2
Liverpool 22kV Dst Lower Bus	9.3	8	0.5	9.4	8.1	0.5	9.5	8.3	0.5
Liverpool 22kV Dst Upper Bus	11.6	10	0.9	11.8	10.2	0.9	12	10.4	0.9
Liverpool 110kV	18.2	15.2	19.7	17.7	15.3	19.9	18.5	16.1	20
Mangere Central	7.9	6.9	8.2	8	6.9	8.3	8.1	7	8.3
Mangere East	8	6.9	8.3	8.1	7	8.4	8.1	7	8.4

Substations	2011			2016			2021		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Mangere West	10	8.7	11	10.1	8.8	11.1	10.2	8.8	11.1
Manly	9.6	8.3	11.1	9.6	8.3	11.1	9.6	8.3	11.1
Manukau	11.8	10.2	12.4	12	10.3	12.6	12	10.4	12.6
Manurewa	11.1	9.6	11.9	11.2	9.7	12	11.3	9.7	12
Maraetai	5.8	5	7	5.8	5	7.1	5.8	5	7
McKinnon	12	10.3	12.9	12.1	10.5	13	12.2	10.5	13.1
Mcleod Road	6.9	6	7.4	6.9	6	7.4	7	6	7.4
McNab	11.2	9.7	12.1	11.4	9.9	12.2	11.7	10.2	12.6
Milford	6.6	5.7	7.2	6.6	5.7	7.3	6.6	5.7	7.2
Mt Albert	4.8	4.1	4.9	4.7	4.1	4.9	4.8	4.1	4.9
Mt Wellington	11.4	9.9	11.8	11.4	9.9	11.8	11.8	10.2	12.1
New Lynn	10.9	9.4	12.1	10.9	9.4	12.2	10.9	9.4	12.2
Newmarket	11.9	10.3	12.5	12	10.4	12.6	12.6	10.9	**13.2**
Newton	7.1	6.1	7.7	7.2	6.2	7.8	7.3	6.3	7.8
Ngataringa Bay	6.3	5.4	6.9	6.2	5.4	6.8	6.2	5.4	6.9
Northcote	6.1	5.3	6.6	6.1	5.3	6.6	6.1	5.3	6.6
Onehunga	7.7	6.6	8.4	7.7	6.6	8.4	7.9	6.8	8.6
Orakei	8.7	7.6	9	8.8	7.6	9.1	9.1	7.9	9.3
Oratia	5	4.3	5.3	5	4.3	5.3	5	4.3	5.3
Orewa	9.2	8	10.5	9.2	7.9	10.5	9.3	8	10.6
Otara	9.3	8.1	10	9.5	8.2	10.1	9.6	8.3	10.2
Pacific Steel furnace 33kV	7.6	6.5	8	7.6	6.5	8	7.6	6.6	8
Pacific Steel 33kV	4.1	3.5	4.1	4.1	3.5	4.1	4.1	3.5	4.2
Pakuranga	8.1	7	8.4	8.1	7	8.3	8.2	7.1	8.4
Papakura	8.1	7	8.4	8.1	7.1	8.4	8.2	7.1	8.5
Parnell	11.9	10.3	12.8	12	10.3	12.8	12	10.3	12.7
Ponsonby	6.5	5.6	7.1	6.5	5.6	7.1	6.5	5.6	7.1
Quay	8	6.9	8.5	8.1	7	8.5	7.9	6.9	8.4
Quay 22kV	17.7	15.1	13.6	17.6	15.3	13.6	17.8	15.4	13.5
Quay 22kV distribution	17.8	15.4	18.5	17.9	15.5	18.5	17.9	15.5	18.5
Ranui	5.5	4.8	5.9	5.5	4.8	5.9	5.5	4.8	5.9
Red Beach	6.3	5.5	6.6	6.3	5.4	6.6	6.3	5.4	6.6
Remuera	7.9	6.8	8.4	8	6.9	8.5	8.3	7.2	8.8
Riverhead	5.1	4.4	6.1	5.1	4.4	6.1	5.1	4.4	6.2
Rockfield	8.4	7.3	8.6	8.5	7.4	8.7	8.9	7.7	9.1
Rosebank	8.8	7.6	9.4	8.8	7.6	9.4	8.9	7.7	9.5
Sabulite Road	10	8.7	10.8	10	8.7	10.8	10	8.7	10.8
Sandringham	8.4	7.3	8.8	8.5	7.4	8.9	8.5	7.4	8.9
Sandringham 22kV	16.4	14.2	16.6	16.5	14.2	16.6	16.6	14.3	16.7
Simpson Road	4.1	3.5	4.3	4.1	3.5	4.3	4.1	3.5	4.3
Snells Beach	2.7	2.3	3.2	2.6	2.3	3.2	2.6	2.3	3.2
South Howick	8.6	7.4	8.8	8.6	7.4	8.8	8.7	7.5	8.9

Substations	2011			2016			2021		
	3P	P-P	P-E	3P	P-P	P-E	3P	P-P	P-E
Spur Road	6.7	5.7	7.2	6.7	5.7	7.2	6.7	5.7	7.2
St Heliers	8.6	7.5	8.9	8.7	7.5	8.9	9	7.8	9.2
St Johns	10.3	8.9	11.2	10.4	9	11.3	10.7	9.2	11.6
St Johns 33kV	16.1	14	16.6	16.4	14.2	16.6	16.8	14.5	17
Sunset Road	12.3	10.6	**13.4**	12.3	10.7	**13.4**	12.3	10.7	**13.4**
Swanson	7	6	7.4	7	6	7.4	7	6.1	7.5
Sylvia Park	8.5	7.4	9	8.6	7.4	9	8.9	7.7	9.4
Takanini	9.1	7.9	9.2	9.2	8	9.3	9.2	7.9	9.3
Takapuna	6	5.2	6.4	6	5.2	6.4	6	5.2	6.4
Te Atatu	11.7	10.1	13.1	11.7	10.1	13.1	11.7	10.1	13.1
Te Papapa	8.2	7.1	8.4	8.3	7.2	8.5	8.5	7.4	8.8
Torbay	6.1	5.3	6.7	6.2	5.3	6.8	6.2	5.3	6.8
Triangle Road	11.6	10	12.4	11.6	10	12.5	11.6	10.1	12.5
Victoria	6.6	5.7	7.3	6.6	5.7	7.3	6.7	5.8	7.4
Waiake	6.5	5.7	7	6.5	5.7	7	6.5	5.7	7
Waiheke	5.3	4.6	6.7	5.3	4.6	6.7	5.3	4.5	6.7
Waikaukau	4.3	3.7	4.5	4.3	3.7	4.5	4.3	3.7	4.5
Waimauku	3	2.6	3.5	3	2.6	3.5	3	2.6	3.5
Wairau	11.3	9.8	12.6	11.3	9.8	12.6	11.3	9.8	12.6
Wairau 33KV	11.5	10	12.8	11.5	10	12.8	11.6	10	12.8
Warkworth	5.5	4.8	7.2	5.6	4.8	7.2	5.6	4.8	7.2
Wellsford	5.7	4.8	6.6	5.7	4.8	6.6	5.7	4.8	6.6
Westfield	11	9.6	12.4	11	9.5	12.3	11.3	9.8	12.7
White Swan	11.6	10.1	12.7	11.6	10.1	12.6	11.7	10.1	12.7
Wiri	11.6	10.1	12.3	11.9	10.3	12.5	12	10.3	12.5
Woodford	6.4	5.6	6.9	6.4	5.6	6.9	6.4	5.6	6.9

Table 2-7 : Fault levels at Vector zone substations

The zone substations where the calculated prospective fault currents are in excess of the 13.1kA rating of the circuit breakers are highlighted in bold. 11kV Busbars with existing prospective fault currents in excess of 13.1kA (Browns Bay, Henderson Valley and Sunset Road substations) are operated in split mode to contain the fault levels to within the rating of the circuit breakers.

2.3.3 Distribution Network

The function of the distribution network is to deliver electricity from the zone substation to customers. It includes a system of cables and overhead lines, operating at 11kV or 22kV, which distribute electricity from the zone substations to smaller distribution substations. Typically up to 2,000 customers are supplied by a medium voltage (MV) distribution feeder, the number being determined by the load density and level of security.

At distribution substations the electricity is stepped down to 400/230V and delivered to customers either directly or through a reticulation network of low voltage (LV) overhead lines and cables. Approximately 30 to 150 customers are supplied from each distribution substation. A typical distribution substation contains an MV (22kV or 11kV) / LV transformer, LV board and MV switchgear.

The 11kV distribution network was originally constructed as an overhead network with interconnected radial feeders. However, since the mid-1960s most new subdivisions have been constructed with underground cables and any new 11kV feeder cables in urban areas are installed underground. The same applies to the 400V distribution network. The 22kV distribution network (around Highbrook industrial development and the Auckland CBD) is newly established and is underground.

There are a number of large customers in the Southern region connected to the network at higher voltage levels. The ownership of the substations serving these customers varies from site to site but generally Vector owns the incoming switchgear and any protection equipment associated with it. The customer owns the transformer(s), any outgoing switchgear and associated protection, and the building.

A more detailed description of the distribution network is given in Sections 5 and 6 of this AMP.

2.3.3.1 Undergrounding

Vector has an obligation to its 75% owner, the Auckland Electricity Consumer Trust, to conduct an undergrounding programme for the Southern region and the percentage of overhead network is gradually reducing. All new subdivisions have been reticulated underground (distribution and LV networks) for the past 40 years. This is required by the local authorities.

As at the end of March 2010, 69% of the distribution (11kV and 22kV) network was underground in the Southern region and 30% in the Northern region. Overall, 46% of Vector's distribution network is underground.

2.3.4 Low Voltage Network

While substantial parts of the existing Vector distribution network are still overhead, all new subdivisions are reticulated underground. Vector has an ongoing undergrounding programme in the Southern region.

Distribution transformers are designed to supply a predetermined number of customers based on an expected after diversity maximum demand (ADMD) and can withstand some cyclic overloading, based on industry standards. The LV cables are configured in a radial formation with limited interconnection capacity to other distribution transformers (LV cables are not sized to supply adjacent substations). In the event that a transformer fails, a mobile generator will be deployed to restore supply while the transformer is replaced. Alternatively, a temporary cable can be installed provided capacity is available from neighbouring substations.

As at the end of March 2010, 62% of the LV distribution network was underground in the Southern region and 47% in the Northern region. Overall, 55% of Vector's LV distribution network is underground.

2.3.5 Protection, Automation, Communication and Control Systems

2.3.5.1 Power System Protection

The main role of protection relays is to detect network faults and initiate power circuit isolation upon detection of abnormal conditions. All new and refurbished substations are equipped with multifunctional intelligent electronic devices (IEDs). Each IED combines protection, control, metering monitoring, and automation functions within a single hardware platform. It also communicates with the substation computer or directly to SCADA central computers over the IP based communication network using industry standard communication protocols.

2.3.5.2 Substation DC Auxiliary System

A substation's DC auxiliary system is the most vital component of each substation - it provides power supply to the substation protection, control, and communication systems, including circuit breaker (CB) control and tripping. The substation's DC auxiliary system provides power supply to the substation protection, automation, communication, control and metering systems, including power supply to the primary equipment motor drive mechanisms.

Vector's standard DC auxiliary systems consist of a dual string of batteries, battery charger, a number of DC/DC converters and a battery monitoring system. The major substations are equipped with a redundant DC auxiliary system.

Vector uses Valve-Regulated Lead-Acid (VRLA) batteries which are safer for personnel, more cost effective and require less routine maintenance. The VRLA batteries are charged with a temperature compensated charger.

To increase system reliability, reduce maintenance costs and increase maintenance personnel safety, a battery monitoring system is fitted to all new installations.

2.3.5.3 Substation Automation (SA)

Substation automation (SA) describes the collection of infrastructure within a substation enabling the coordination of protection, automation, monitoring, metering and control functions, and utilising substation internal communications network infrastructure. Vector's substation automation system is based on resilient optical Ethernet local area network running IEC 61850 compliant IEDs.

2.3.5.4 Feeder Automation (FA)

Feeder automation (FA) can be defined as schemes of equipment (automated switches, auto-reclosers etc) that are capable of acting without human intervention in order to minimise outages, restore supply or carry out other network/asset automation functions e.g. substation off-loading.

The feeder automation schemes are frequently interfaced to the network control centre for remote indication, control and data acquisition (SCADA functions).

The feeder automation in its present implementation state enables SCADA functionalities, auto-reclosing, auto-sectionalising, feeder reconfiguration, fault detection and voltage control.

2.3.5.5 Supervisory Control and Data Acquisition - SCADA

A typical SCADA system is hierarchically architected and consists of:

- Master Station – centralised computer systems with SCADA application software, workstation and HMI (Human Machine Interface);
- Communication protocols;
- Communication systems; and
- Field Installed Intelligent Electronic Devices (Remote Terminal Units, IEDs).

A SCADA system enables remote control (telecontrol) of power system equipment (e.g. switchgear, power transformers) and remote measurements (telemetry) of power system current and voltages.

Currently two SCADA master stations are being used for the electricity SCADA:

- Siemens Spectrum Power TG; and
- LN2068 with Foxboro Workstations.

A Siemens Spectrum Power TG master station has been deployed for monitoring and control of the Southern region electricity network, while LN2068 is used for the Northern region. Vector's modern SA system and other field IEDs installed in recent years have been, and continue to be, interfaced to both SCADA master stations, enabling migration process of Northern SCADA information into PowerTG. Once migration is completed, LN2068 will be retired.

2.3.5.6 Remote Terminal Units (RTU)

An RTU is a microprocessor controlled electronic device which interfaces objects in the physical world (e.g. switchgear, power transformers) to a distributed control system or SCADA system by transmitting telemetry data to the system and/or altering the state of connected objects based on control messages received from the system. An RTU can act as a substation.

For remote control, the traditional RTU solution has been to install an RTU device as an interface between the network control SCADA master station and the substation primary equipment (switchgears, power transformers). This functionality is in modern SA systems being distributed to IEDs installed within substations.

Over time a number of different RTUs have been installed in Vector's network, many of which are nearing the end of their technical life or are obsolete. Vector has embarked on a replacement programme enabling a standard RTU to be deployed across the network. RTUs installed in the Northern region are interfaced to both SCADA master station systems.

2.3.5.7 Communication Protocols

A variety of SCADA communication protocols are presently used to communicate between the various SCADA systems and different types of IEDs installed on the network. Vector's current standard for internal and external communication systems is IEC 61850 standard. DNP3 is also used as an interim solution.

2.3.5.8 Communication System

Vector's communications network consists of differing architectures and technologies, some of which are based on proprietary solutions. The physical network infrastructure consists of a mix of optical fibre, copper (Cu) wire telephone-type pilot cables and third party radio communication systems.

The communications network is used for protection signalling, SCADA communications, operational telephony, access security, metering, remote equipment monitoring and automation.

Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and internet protocol (IP) based communication technology.

2.3.5.9 Energy and Power Quality Metering

Vector's energy and power quality (PQ) metering system consists of a number of intelligent web-enabled revenue class energy and PQ meters installed at GXPs and zone substations. The meters communicate to the metering central software over an ethernet-based IP routed communication network.

The metering system provides Vector with essential information about the quantity, quality and reliability of the power delivered to Vector's customers, and is currently used to:

- Improve asset utilisation by managing network peak demands;
- Provide PQ and load data for network management and planning purposes;
- Provide information to assist in the resolution of customer-related PQ issues; and
- Contribute to the power system stability by initiating instantaneous load shedding during under-frequency events.

2.3.5.10 Load Control Systems

Vector's load control systems consist of audio frequency ripple, pilot wire and cyclo control types. The load control systems offer the ability to:

- Control residential hot water cylinders;
- Control street lighting;
- Meter switch for tariff control;
- Time shift load to improve network asset utilisation;
- Time shift load to defer reinforcement of network assets; and
- Manage GXP demand charges from Transpower.

Load control equipment utilises older technology, much of which is approaching the end of its life. As newer customer metering ("smart meters" or associated intelligent home hubs) and communications technologies are rolled out, alternative means of load control will become possible. It is, therefore, anticipated that the existing load control systems will be phased out. Strategies for the transition are being developed. (See Section 3 for a discussion.)

2.3.6 Lichfield

Lichfield substation was established with two 20MVA 110/11kV transformers, from a tee off the Transpower 110kV lines. Vector owns the transformers and the 11kV cabling and switchgear on the Lichfield site. The two transformers are Y-y vector group (the only Y-y units within the Vector network). The map in Figure 2-11 shows the location of Lichfield GXP.

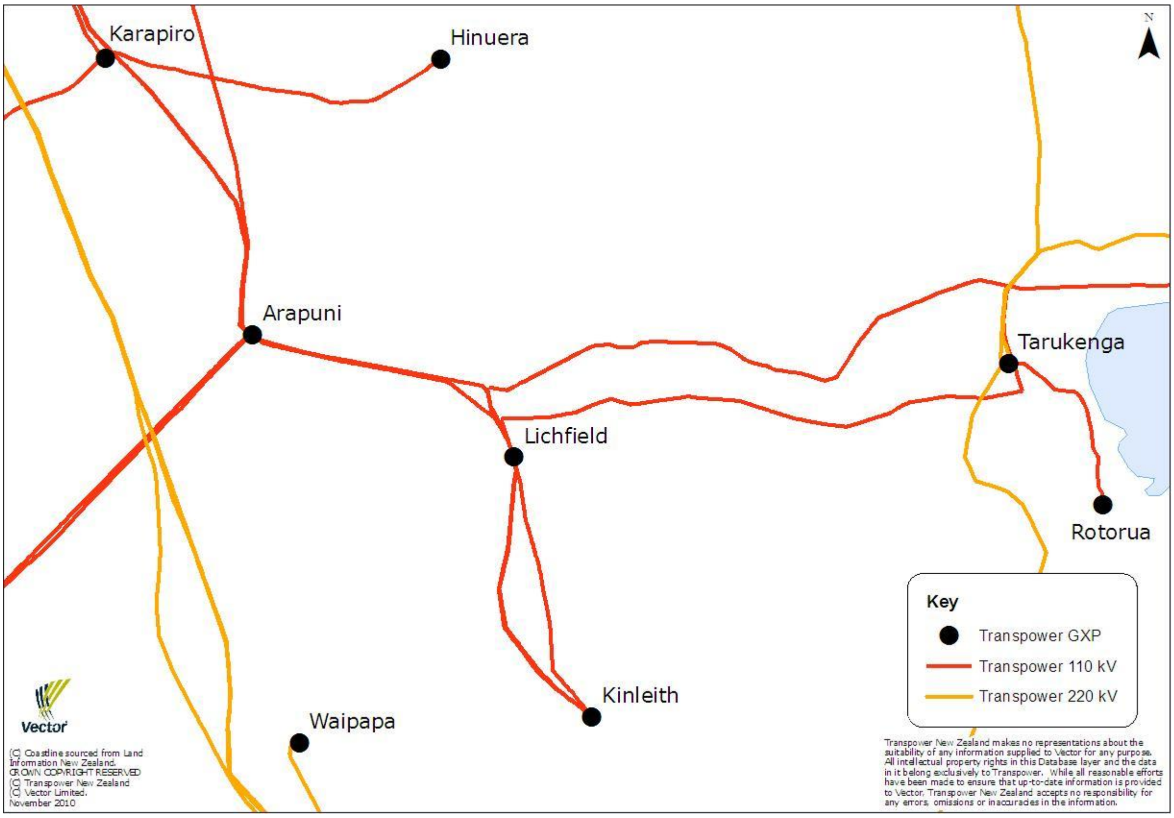


Figure 2-11 : Location of Lichfield GXP

2.3.7 Vector assets installed at Transpower GXPs

For practical reasons Vector has installed some of its equipment at Transpower GXPs, with agreement from Transpower. These assets are described below.

2.3.7.1 Power equipment

Vector owns the 33kV feeder circuit breakers at Wellsford GXP, Albany GXP, Hepburn Road GXP (except for the two Rosebank feeders) and Henderson GXP. These circuit breakers were purchased from Transpower. Vector has responsibility for their maintenance and operations.

Vector owns all 22kV, 33kV and 110kV sub-transmission cables and overhead lines terminating onto Transpower's 22kV and 33kV switchboards at all GXPs feeding its network, irrespective of whether the 22kV and 33kV circuit breakers are owned by Vector or Transpower.

The Penrose end of the CBD tunnel (connecting Penrose GXP to the Auckland CBD) is constructed within the Penrose GXP site boundary. This tunnel accommodates Vector's 33kV and 110kV cables.

2.3.7.2 Protection and communications equipment

Vector uses unit protection in the Southern region as primary protect for its sub-transmission network. As part of the unit protection schemes, protection relays are installed at GXPs where the sub-transmission circuits are connected. Other parts of the protection schemes include control wiring, batteries and chargers. Communications equipment including RTUs, pilot wires, etc are also installed as part of Vector's SCADA and control system.

Vector has installed power quality meters and check meters at GXPs to monitor power quality and energy injected into Vector's distribution network.

2.3.7.3 Load control equipment

Vector's ripple injection plants in the Southern region are connected to its sub-transmission network. For zone substations supplied from the sub-transmission network connected to a Transpower GXP, the ripple injection plants are located at the respective GXP. For zone substations supplied from the sub-transmission network connected to a Vector bulk supply substation, the ripple injection plants are located at the respective bulk supply substation. Ripple injection plants in the Northern region are 11kV rated and are located within the zone substations.

2.4 Justification of Assets

Network assets are created for a number of reasons. While asset investment is often the most effective and convenient means of addressing network issues, Vector also considers other solutions to network issues and applies these where practical and economic. Such alternatives may include network reconfiguration, asset refurbishment, adopting non-network solutions (such as distributed generation) or entering into load management arrangements with customers.

The key factors leading to asset investment at Vector are:

- Health and safety: where health and safety concerns indicate the need for asset investment, this takes priority;
- Legal and regulatory compliance: ensuring Vector is not in breach of statutory obligations of electricity service providers or regulatory requirements such as satisfying the voltage limits;
- Capacity: maintaining sufficient network capacity to supply the needs of consumers is a key driver for asset investment;
- New developments: where new building or urban developments occur, or existing developments are extended, this usually requires investment in network assets;
- Security of supply standards: Vector is committed to meeting its security of supply standards, and potential breaches of these often indicate a need for asset investment. Network assets are constructed to provide both capacity and security;
- Reliability: Vector's customers expect a certain level of reliability of supply. Decisions in the optimal expenditure to achieve the target reliability often involve optimising the capex/opex mix. On occasions, more assets are required to reduce opex with the overall result of reducing costs in the long term;
- Customer requirements: assets are often installed at the request of customers (who then contribute to the investment cost) such as requiring higher security;
- Renewal: assets are usually replaced when they have deteriorated to the extent that they pose a safety or reliability risk, or have reached the end of their useful lives (where maintenance or refurbishment start to be more expensive than replacing an asset);
- Refurbishment: investing to prolong the useful lives of assets when it is economic and safe to do so; and
- Technology improvements: when technology becomes obsolete and assets can no longer fulfil the basic requirements of a modern, effective network, this may give rise to replacement expenditure.

Vector's network investment has always been prudent, meeting only realistic network requirements. This is also illustrated by the most recent optimised deprival valuation (ODV) of the electricity network carried out in 2004. For this ODV, Vector recorded $51.6 million of optimisation for its Auckland (excluding Wellington) assets, being assets deemed unnecessary for current requirements due to stranding, over-capacity for current demand or other similar factors. This figure equates to 3.4% of the corresponding ODV, a very small margin.[14] Of the assets affected, all were optimised down to a lower capacity and not optimised out. With the demand growth in the past six years, it is expected that a significant portion of these optimised assets will be reinstated, should an ODV be carried out again.

In submitting business cases for project approvals, planners are required to develop credible and viable options (including network and non-network options) for evaluation. Evaluation criteria included in the business case include economic efficiency, financial viability, technical suitability, strategic fit and a risk assessment. This further ensures prudent investment decisions.

Several factors influence how assets are selected and the manner in which they are implemented.

- Network design standards

  Vector has developed a detailed network security standard, which sets out the basic requirements for network planning for the distribution and sub-transmission networks (refer to Section 5 of this AMP for details). These standards define largely the stage at which network reinforcement (i.e. new assets) becomes essential, and the capacity to which new installations should be built.

  We have adopted a probabilistic security standard (although the standard is expressed in deterministic language to allow easier understanding by the reader) rather than the more conventional deterministic standards used by most distribution utilities. Our security standard is comparable with, but more cost-effective than, that of most other distribution utilities in New Zealand and Australia.

  In practice, the security standard allows Vector to operate its sub-transmission network to a level marginally below N-1 for a small number of peak-demand hours during a year (except in the Auckland CBD, where higher standards apply).

  To manage supply risk, Vector has put in place a system of operational contingency plans (which are regularly updated). In addition, assets are used to their cyclical rating capacity – generally allowing short-term loading to exceed the normal long-term equipment rating. This approach allows Vector to maximise asset utilisation.

  Capacity and security are not the only criteria for the design of the distribution network. In Section 5 other planning criteria are also described.

- Optimising installations

  When a potential network issue or constraint is identified, project options will be developed and the optimal (usually least life cycle cost) solution will be adopted. The optimal solution may not have the lowest initial capital cost or be the lowest capacity solution.

[14] Even this figure gives an over-estimate of "stranded assets" given the unrealistic asset planning horizons (from an engineering/economic perspective) provided for in the ODV Handbook.

- Equipment standardisation

  To minimise cost in the long-term and to ensure optimally rated equipment is installed to meet a range of possible situations, Vector has a policy of using standardised equipment on its network. For example, Vector has standardised on 20MVA and 10MVA for power transformers. 20MVA transformers are used in high load density urban areas whereas 10MVA transformers are used in lower load density rural areas.

  Standardisation helps to reduce design and procurement costs during the establishment phase, increase operational flexibility and makes equipment maintenance more effective. It also allows more effective strategic spares management.

- Customer-specific assets

  From time to time, Vector builds dedicated assets to supply customers at their requests based on agreed commercial terms. Examples are Lichfield and Auckland International Airport (AIAL).

- Life-cycle considerations

  Vector adopts a life cycle cost approach to choosing network solutions and assets. This means the lowest cost short-term solution may not always be adopted. For example, Vector builds indoor substations within concrete buildings to accommodate switchgear and auxiliary equipment, although outdoor equipment is initially cheaper to install. Over time the initial additional costs are offset by lower maintenance costs, more secure and reliable operations, and longer life-spans.

- Historical considerations

  Load growth, load density and historical network architecture and equipment standards can result in varying types of assets, states of security and asset condition throughout the network. While historical network architectures and equipment standards converge over time, replacing well-functioning assets to achieve such alignment in the short term can generally not be economically justified. However, as failing assets are replaced or new assets added to the network, these are generally designed to comply with the present specifications.

- Equipment utilisation

  The utilisation (the ratio between the peak demand on an equipment over its capacity) of Vector’s feeders and zone substations are in general fairly high. The utilisation graphs shown in section 4 indicate that the majority of zone substations are utilised to 65% and 80% of their capacities in the Northern and Southern regions respectively.

  The network architecture of the networks in the two regions inherently causes a higher utilisation in the Northern region. This higher utilisation also reflects the largely residential characteristics of the region (compared to the high concentration of industrial and commercial load in the Southern region).

2.4.1 Determination of capacity of new equipment

As stated earlier, Vector has a policy of using standard equipment on its network to minimise long-term cost. For example, standard power transformers are 20MVA and 10MVA units. 20MVA transformers are used in high load density urban areas whereas 10MVA transformers are used in lower load density rural areas.

The key factor in deciding the standard capacities (20MVA and 10MVA) of power transformers is the load density of the area being supplied. While economy of scale suggests the use of large capacity transformers, higher capacity zone substations will result in a larger supply catchment area (for the same load density) and longer distribution feeders. Larger supply catchment areas will also result in zone substations further away from GXPs, thus requiring longer sub-transmission feeders. Deciding the optimal economic capacity of standard urban transformers requires optimisation between cable and transformer costs to achieve the lowest overall cost per MVA of network capacity. Scenarios (of different transformer capacities and feeder lengths) were developed for analysis, considering a range of equipment costs and load densities. This resulted in a decision on the standard transformer capacity of 20MVA. Other factors considered in the exercise include impact of transformer capacity on fault level, transformer impedance, reactive power and tap changer / voltage control. Once the capacities of transformers are determined, cable sizes are designed to match.

For power transformers used in rural zone substations, voltage performance of the distribution network is another important deciding factor in addition to the factors stated above. The result of the analysis for these areas indicated 10MVA is the most appropriate transformer capacity.

Electricity
Asset Management Plan
2011 – 2021

Future Vision and Strategy – Section 3

[Disclosure AMP]

Table of Contents

List of Figures

3. Future Vision and Strategy

3.1 Overview

The environment within which electricity distribution businesses operate is undergoing considerable change:

- From a technological perspective, developing trends in consumer appliances, technology convergence, renewable generation and an increasing ability to build distributed intelligence into networks have major potential for improving the customer experience and network efficiency and reliability. However, it also holds a very real risk of forcing major network augmentations[1] and/or causing stranded assets[2]; and
- Societal changes are also having a marked impact on network operations and asset management decisions due to changing customer expectations and increased awareness of energy-related matters.

Making investment decisions on major, long-life assets in a changing environment poses challenges. Vector has developed a future vision to help guide asset management strategy to ensure its networks can cope with the anticipated changes and it is well-positioned to make best use of the opportunities offered. This vision will be regularly reviewed to take into account ongoing changes to the environment Vector operates in.

Through its ownership of Advance Metering Systems (AMS) – a leading provider of smart meters for the industry - and by virtue of its long-term involvement in installing fibre optic networks in the Auckland region, Vector is ideally placed to maximise the benefits from developing technology for its distribution network. This also supports the Vector asset management strategy that is based on an all-encompassing continual efficiency improvement drive, helping ensure Vector achieves commercially sustainable returns on investments while providing a reliable, safe and affordable electricity supply.

3.1.1 Focus on Investment Efficiency

Vector seeks to continually improve the efficiency of its investment decisions. To help drive this, specific business-wide targets have been established to improve capital efficiency over the next three years. The targets will be achieved through a combination of continual improvement and innovation:

- Keeping an open mind ("how we can" not "why we can't");
- Broadening thinking around potential asset solutions, including multiple utility and non-network solutions;
- Leveraging previous smart solutions into new areas of application;
- Keeping abreast of solutions others are applying and relating these to Vector's challenges;
- Taking advantage of new technologies that enable solutions not previously possible;
- Making better decisions through better information and analysis;

[1] Through increasing electricity demand peaks.

[2] When equipment becomes obsolete at an early date, or demand shifts lead to redundant capacity.

- Enhanced, robust decision-making processes (a “value engineering” type approach) which seek broad and effective input to potential solutions and includes review steps to support continuous improvement; and
- Making continuous incremental improvements in our project planning and delivery.

These efficiency factors are reflected at all levels of asset management at Vector – from the asset design phase, through the procurement and construction phase and into the lifecycle operational phase.

Systems and processes have been established to track efficiency progress and to ensure that enhanced efficiency considerations are built into asset decision making processes at all levels.

3.1.2 Clear Understanding of Future Network Demands and Challenges

Recent worldwide development trends in consumer technology and renewable generation make it imperative for Vector to understand the potential impact of these emerging technologies on the network and to develop strategies so that Vector’s network is ready to cater for these technologies and meet new consumer demand.

Vector has therefore:

- Considered emerging technologies that are likely to have significant impacts on the electricity and gas networks;
- Developed a view as to how the network may be affected by these technologies in 5-20 years time; and
- Developed strategies to mitigate potential adverse impacts on the network, capture opportunities and to shape the development of the network.

3.1.3 Leverage Technology

Developments in information, communication and automation technology present opportunities to introduce greater levels of intelligence into the distribution network.

To date, cost factors have limited the intelligence in the network to the higher voltage (11kV and above) parts. Technology developments are now making it operationally feasible to extend to the lower voltage parts of the network.

The outcomes from this offer the potential to:

- Improve asset utilisation resulting in deferred investment expenditure;
- Increase network reliability and reduce restoration times; and
- Lower operational costs.

A number of trials of potential technologies will progress over the coming months to test performance and integration with Vector’s existing systems, which will inform our future strategies in this regard.

One area of concern that will have to be addressed is the regulatory and pricing implications of investment in emerging technologies. From a consumer perspective there may be clear efficiency gains achievable through adopting the emerging technologies, but it is less clear the regulatory framework and the New Zealand electricity market structure will provide appropriate incentives or rewards for any particular sector of the market, including electricity lines business, to unlock the full available potential. If the correct regulatory long-term incentives are not in place the efficiency gains may not be made.

Vector's "intelligent network" strategy is detailed in Section 3.4 below.

3.1.4 Constraints on implementing new solutions

Vector is actively pursuing optimal investment- and energy-efficiency through embracing innovation, new technology and solutions. However, we note that some aspects of the electricity market structure in New Zealand and the commercial regulation of electricity distribution business constrains our ability to maximise the potential benefit that could be derived not only for our customers, but also for the wider New Zealand economy. These factors are being discussed in other forums, but the main aspects impacting on asset management planning, are summarised below:

- While Section 54Q of the Commerce Act directs the Commerce Commission to encourage energy efficiency, the Commission has yet to implement policies to comply with this section and few incentives exist for electricity distribution business to alter their investment practices in this regard;
- The separation of the retail and distribution functions has led to a distance between electricity distribution businesses and their customers, especially where interposed relationship models exist. Many of the potential efficiency benefits that are likely to arise from technology changes will rely on close interaction between distribution businesses and end-users, including:
    - Interfacing smart home devices with network management tools;
    - Creating pricing structures that incentivise customers to shift consumption to off-peak periods (and providing them the means to effectively do so) and having these signals flow through to customers; and
    - Better understanding of customer consumption patterns, allowing optimal network planning and utilisation.

  To fully embrace the opportunities offered by evolving technology will require a much closer relationship between lines companies and end-users.
- The current regulation of network quality is aimed at maintaining historical performance levels and there is no incentive to improve on this. A key attraction of improving technology is the ability to improve network reliability and fault response time, but absent an incentive to do so, it is not commercially feasible to invest in this ability; and
- Under current price-setting arrangements it is only commercially feasible to invest in energy-efficient network solutions where these are cheaper than (on a life-cycle basis) or allow deferment of conventional network investments. These are narrow benefits, accruing to the electricity distribution business (and ultimately to its customers), but many opportunities to realise wider economic benefits are likely to be foregone. Downstream benefits such as allowing deferment of transmission or generation investments are not reflected in the business cases for investments that have to be funded solely by the distribution companies.

3.2 Future Technology Assessment

A broad scan of technologies that could impact on Vector's network has been undertaken. The technologies that are more likely to have significant impact on the electricity network in the short to medium-term are:

- Heat pumps;
- Photo-voltaic (PV) panels;
- Electric vehicles (EV);

- Light emitting diode (LED) lighting;
- Battery storage; and
- Smart home technologies.

It is also noted that fuel cells and V2G[3] (vehicle to grid) application could have significant impacts on how the electricity network operates. Fuel cells have not been included in the current list pending a technological breakthrough to enable practical application and to reduce cost of production. V2G application is dependent on the uptake of electric vehicles and future development of battery and charging technologies. Development of both these technologies will be monitored.

3.2.1 Understanding the Impact of New Technologies

Extensive research has been carried out to analyse the experience of overseas utilities facing similar opportunities and threats from emerging technologies. These have then been reconciled with local situations to ensure the relevant and appropriate experience has been applied.

Technology change could have a significant impact on the load profile of Vector's electricity network over the next 10-15 years. Some technologies are likely to increase peak loads (and/or energy usage), others to reduce it and still others to change the time of day at which energy is used, resulting in significant potential changes in peak demand patterns and overall electricity usage. These changes could have significant flow on effects on Vector's asset investment strategy.

Some of the developments that are most likely to have a material impact in the near to medium-term future are discussed below.

3.2.1.1 Solar PV

Photovoltaic (PV) panels convert sunlight into electricity. Distributed PV refers to the installation of the panels on buildings that are already connected to an electricity distribution grid, with the panels connected to the grid. By drawing power off the PV panels, households and commercial buildings reduce their purchases of electricity from the grid, thus saving money. They can also sell any excess electricity into the grid[4], thus improving the economics of the PV installation.

Technology developments over the past five years have seen the cost of photovoltaic panels reduced from around $15 per watt in 2005 to around $5 per watt in 2010. The cost reduction has been achieved through advances in the chemistry of the panels, manufacturing efficiencies and through overcoming material and manufacturing capacity bottlenecks.

It is widely forecast that the prices of PV will continue to fall and are likely to provide an economically attractive alternative to grid electricity in the next 5-7 years. For some remote locations, even today a PV solution (including backup batteries) provides the most cost-effective solution (compared to the cost of extending the conventional supply network).

Internationally, incentives (subsidies, feed in tariffs, etc) offered by governments such as Germany, Spain, California and Australia have accelerated the uptake of PV. This increase in demand in turn drives down the cost of manufacturing and provides incentives to further develop the technology. Although it is not foreseen that the New

[3] V2G is the short description for vehicle to grid. This describes the use of the energy stored in the batteries of an electric vehicle to supply the electricity network at times when the grid has difficulties supplying the customer's needs.

[4] On the proviso that certain technical and safety requirements are met.

Zealand government will offer similar incentives in the near future, the downward trend in price could eventually provide sufficient incentives for PV uptake.

The introduction of PV on the network is expected to reduce average feeder loading (utilisation). PV output is however intermittent, and without further energy storage or other localised forms of generation, is not a reliable energy source. During periods where PV units are inefficient (for example at night, or during heavy cloud conditions) electricity would be drawn from the grid. Should this occur during peak consumption periods, as is likely from time to time, the resulting peak demand may not change from current levels. From a distribution network perspective, assuming existing reliability levels would be maintained, it is, therefore, not foreseen that the delivery capacity can be reduced as PV is introduced (at least until effective energy storage solutions are developed).

Distributed generation from PV may impact on network security, as the effective load reduction would increase the backstop capability at zone substations. This, however, would again be intermittent (unless additional energy storage devices are available) and, therefore, is not a reliable alternative to network capacity.

Network modelling has been undertaken by Vector to understand the impact on the network of PV under various “penetration rates” (capacity of installed PV as a percentage of total network demand) scenarios. Of interest is the amount of PV that would need to be installed beyond which there could be two way power flow (flow back up the network) and associated over-voltage issues. The analysis found very high penetration rates (above 20%) would be required for there to be general network issues. This greatly exceeds the forecast uptake rate of 5% in the next 25 years. It is recognised, however, that there may be localised issues in areas of high concentration of PV e.g. very large PV installations on a number of commercial buildings in one area or large PV installations on a long rural line. Potential technical solutions to such issues are being explored.

3.2.1.2 Electric Vehicles

Most major car manufacturers are planning launches of plug-in electric vehicles in 2011/2012. While energy cost per kilometre travelled are falling, electric vehicles currently require a battery, which adds around $10,000 per vehicle compared to equivalent petrol powered vehicles. This premium is expected to reduce as design and manufacturing improvements to electric vehicles and batteries are made. In addition, increases in oil price due to scarcity and demand are likely to make electric vehicle options more attractive in future.

Based on vehicle sales data, studies by the Ministry of Economic Development (MED) and international EV forecasts, it is expected that there may be in the order of 50,000 electric vehicles in Auckland by 2020 and 150,000 by 2025. There is considerable uncertainty around the likely impact electric vehicle charging may have on the network. The reasons for this are:

a. **Plug in hybrid versus pure electric**: While some vehicles to be introduced will be pure electric (e.g. Nissan Leaf), others will be hybrid vehicles (Toyota and Honda) which have a smaller battery capacity for short trips (30km) and a conventional petrol engine for longer trips.

b. **Charging location and time:** Charging will likely be achieved through a mix of public or work place charging stations and at home charging. Depending on vehicle usage, charging may occur in early evening (if used as a work commute vehicle) or at any time during the day if the owner is home based.

c. **Charging rate:** Vehicle manufacturers may provide both “normal charge” options (10 amps) and rapid charge (60 amps).

We have considered a variety of scenarios and modelled the network impacts for each. For the scenario where 80% of vehicles are plugged-in to charge at peak times (at normal charging rates), additional network investment of $120m over 15 years would be required to manage the additional demand. While pricing signals may provide incentive for customers to charge at off-peak times, the level of incentive able to be provided through distribution tariffs may not be sufficient to change consumer behaviour. The average daily charging cost (based on 40km daily usage) would be around $1.50 at 25c per kWh.

Potential direct control of charging is being considered as part of a wider project to develop a strategy for demand management (see Section 3.5). It is estimated 40% of charging will be conducted using a public charging network. The key issue is the high upfront cost of developing this network, while electric vehicle numbers are slowly growing e.g. charging stations currently cost between $5-10k per unit. A few large cities are building limited trial networks using public funds e.g. London. The developing of such a public charging network will need further careful evaluation to establish its commercial viability.

3.2.1.3 Heat Pumps

Heat pumps are becoming a popular option for space heating and cooling Auckland homes. The Building Research Association of New Zealand (BRANZ) has undertaken comprehensive research of heat pump uptake and is forecasting the trend to accelerate. Currently 10% of Auckland homes have a heat pump installed and this is modelled to increase to 50% by 2025.

The principal impact on the electricity network will be a significant increase in summer load in residential areas on days when heat pumps are used for cooling. The current maximum heat pump demand in summer is around 30MW. This is forecast to increase to 190MW in 15 years (maximum network demand for Vector's network is currently around 1,800MW). During summer, the capacity of underground cables is reduced by around 30% due to temperature effects. At the expected rate of penetration, heat pump cooling loads are likely to introduce summer peaks (higher than winter peak demand) in residential areas (commercial feeders already experience these peaks). The additional investment needed to reinforce the network to meet the forecast increase in summer demand is estimated to be $100m over the next 10 years. Winter peak demand is expected to drop initially as heat pumps are installed to replace existing less efficient resistance heaters. Over time, however, winter peak demand is expected to creep up as consumers start to utilise the heat pumps for longer periods to raise home comfort levels.

To manage the effect of increased summer peak demand, consideration is currently being given to the use of pricing signals to signal the cost to the network of usage during summer peaks and the potential for direct control of heat pump thermostats to manage network issues (see Section 3.5).

3.2.1.4 Advanced Meters and Smart Home Technologies

Technology which supports intelligent management of energy is beginning to be deployed globally. The current roll out of advanced meters is a foundational step. In their most basic form, the meters will provide consumers with improved visibility of their energy use and provide a platform to support "time of use" rates for electricity consumption. International experience of smart meter deployments have shown savings of 5% energy consumption and 2% peak demand reduction following installation of smart meters.

Vector (through AMS) is a leading provider of smart meters to the New Zealand market. By virtue of using a highly flexible, advanced meter type for its roll-out, several further benefits can be realised from the meters[5], including:

- Load control applications, using conventional ripple control (Decabit), radio-based, GPRS-based or fibre-optic based means of communication. This can be used on conventional hot-water control systems, or as an interface to other home appliances.
- Interface to Home Area Networks (HAN), supporting customer-based load control or energy-saving applications.
- Signalling electricity costs and usage rates to customers.
- Providing real-time energy flow data to be used in smart network applications.[6]
- Measurement of two-way power-flow – accommodating distributed generation sources.
- Measuring power quality and voltage levels.
- Providing an exact location and record of power outages.

Other potential future developments of smart home technologies include:

a. **In-home displays:** Dedicated displays or internet displays (e.g. Google Powermeter), providing consumers with greater understanding of their energy use. They will typically include analysis tools to identify potential savings through altering times that appliances are used, or savings from investing in more energy efficient options.

b. **Smart plugs/thermostats:** These devices communicate with a suitably equipped smart meter or an energy management hub to turn power on or off to wall sockets or to adjust the thermostat by a programmed amount. For example, adjusting the thermostat of a heat pump from 24 to 22 degrees during winter peak periods.

c. **Smart appliances:** Include communication capability such that they can respond to signals from smart meters or energy management hubs. For example, signal not to run refrigerator's defrost cycle during a certain time period.[7] The appliances will also report their energy consumption.

d. **Energy management "hubs":** Energy management hubs provide central control and communication to a number of appliances or other loads/energy sources at the customer's premises. The hubs allow the consumer and/or power companies to set rules as to how energy is to be managed. Communication with the hub is either through a smart meter, or directly. Several major companies such as Intel, GE, Control4 and Cisco are developing products to provide the above functions. The rules can be set to respond to the customers' needs as well as any pricing incentives from power companies.

Vector is developing a demand management strategy designed to take account of the technology changes that are emerging. A key principle in demand management is the recognition that there are forms of electricity usage shifting that can have little or no negative impact on consumers, but can offer significant savings (and, therefore, lower electricity charges to consumers) in network costs. Vector's demand management strategy is detailed in Section 3.5.

---

[5] This may require the meters to be fitted with some additional hardware devices, but the potential to do so is in place.

[6] This requires a fast two-way communication medium.

[7] A switch in the time the defrost cycle occurs will have little or no negative impact on consumers, while it could offer benefits to the operation of the network.

3.2.1.5 Battery Storage

Battery technology has been the subject of major development over the past five years. This has been driven both by electric vehicle developments and by recognition of the challenges of incorporating intermittent renewable energy into electricity networks. There are a number of different battery technologies being developed for different applications including sodium sulphide, flow batteries, lithium ion as well as traditional lead acid batteries. Technology improvements as well as manufacturing efficiencies have seen costs falling significantly over the last two years.

An initial project to evaluate the potential of battery storage as a network solution has been completed. The project was designed to understand the sizing and economics of using batteries at zone substations, distribution substations and customer premises to provide either security of supply or load shifting advantages. Various battery technologies were evaluated.

The investigations concluded solutions involving batteries are at present still higher cost than traditional network solutions. (The cost differences in some scenarios are within 20~30%.) Given that costs of some battery technologies have seen large reductions in the past 12 months, distributed battery storage could however provide a feasible alternative in the next three to five years. Further analysis will be undertaken, which may lead to the deployment of field trials to improve understanding of the practical application of battery solutions.

3.2.1.6 LED Lighting

Technology developments in light emitting diodes (LED) lighting have led to LED replacements for most standard domestic and commercial applications. LED bulbs use around 10%-15% of the energy of incandescent and halogen bulbs and around 70% of typical commercial fluorescent tubes. As well as being energy efficient LED bulbs last for around 30,000 hours, which reduces replacement costs (because they don’t need replacing as often). While providing similar energy savings to compact fluorescents (CFL’s), it is anticipated that LED bulbs will prove more popular in the longer-term because of light quality, instant brightness, improved aesthetics and the absence of mercury.

Currently LED bulbs are expensive (around $50 for a standard 60W bulb) which is limiting uptake. Prices are forecast to reduce by 50% over the next 12 months. At current prices, payback in energy savings is only around two to three years and bulb life is expected to be 15 years plus so the economic case for LED lighting is improving.

Lighting accounts for around 20% of peak residential network demand. Currently CFL’s only account for around 5% of light bulbs in homes. There is, therefore, scope for a significant reduction in peak demand if there is widespread uptake of LED bulbs in residential areas.

Further evaluation of the potential application of LED bulbs is continuing, with field trials in New Zealand likely in 2011.

3.2.2 Action Plan – Preparing for Future Technologies

Vector is in the process of developing a range of strategies to deal with anticipated changes in future technology and electricity consumption patterns, including the required expansion of our information management infrastructure.

Aspects that will be covered under these strategies include:

- Demand and energy management;
- Distributed generation;

- Smart meters and home management hubs;
- Energy substitution; and
- Smart distribution networks.

Flowing from work done to date in these areas, Vector has identified a number of areas where it will keep a watching brief, ensuring the company is well-prepared to deal with the changing environment. Key aspects being monitored include:

- Uptake of heat pumps, using industry statistics on installations;
- Summer peaks on residential feeders to check for signs of heat pump use on hot days (annual action);
- International developments of:
  - Electric vehicle and battery technologies;
  - Availability and eventually uptake of EVs; and
  - Charging infrastructures.
- Price trends of solar PV;
- Price trends and technological development of LED lighting;
- Impact of smart meters/time-of-use pricing on residential feeders;
- Developments of home energy management systems, the role of smart meters and the development of smart appliances; and
- Fuel cell and battery storage developments.

3.3 Strategies for Long-term Network Development

3.3.1 Very Long-Term Demand Projection

As part of the process for preparing the very long-term (>50 years) network development plans for the Northern and Southern regions, an exercise was carried out to predict the very long-term load distribution for the whole of Vector's supply area. The very long-term load distribution assumes the area is developed to its full potential based on the existing designated land use zoning by the city and district councils in their district plans and a continuation of the existing consumption behavioural trend. Based on these assumptions, the total loads in the very long-term for the two regions are estimated at:

Auckland CBD	1000MVA
Southern region (except the Auckland CBD)	2500MVA
Northern region	1500MVA

(The above figures represent the upper limit of demand growth in the regions when the land is developed, occupied and utilised to their full potential, if it is ever developed to that extent, based on the existing consumption trend. The demand increase caused by emerging technologies has not been included in this forecast.)

By comparison, the 2010 non-coincident demand for the two regions is about 2000MVA. The potential demand increase in the very long-term is, therefore, about 150% over the existing demand.

3.3.2 Long-term demand position

According to the Regional Growth Strategy (RGS) developed by the (previous) Auckland region's mayoral forum, the region is to be developed to accommodate a population of two million by the year 2050. The plan is to accommodate about a quarter of the population in higher density, multi-unit accommodation while the remainder would live in lower density suburbs and rural areas. The strategy allows a coordinated approach to transport, land use and other resources planning.

Based on the very long-term demand distribution study, the technology roadmap study and the ten year load forecast (2010-2020), an indicative long-term demand projection for the next seventy years is presented in Figure 3-1. The straight line projection (instead of an annual growth percentage) reflects the historic growth pattern (see Section 5.3 for a discussion).

The red (solid) line represents the demand based on the present consumer behaviour, whereas the green (dotted) line includes the demand due to the introduction of new technologies and appliances (such as electric vehicles and heat pumps) that are not widely used today. Detailed, more accurate forecast of the first ten years (from 2010 to 2020) of the projection is given in Section 5.4 of this AMP.

The newly formed Auckland Council is in the process of developing a "spatial plan" to guide the development of the city in the next twenty to thirty years to accommodate the anticipated population growth to 2.2 million by 2030. When completed (scheduled for the end of 2011), the "spatial plan" will supersede the Regional Growth Strategy.

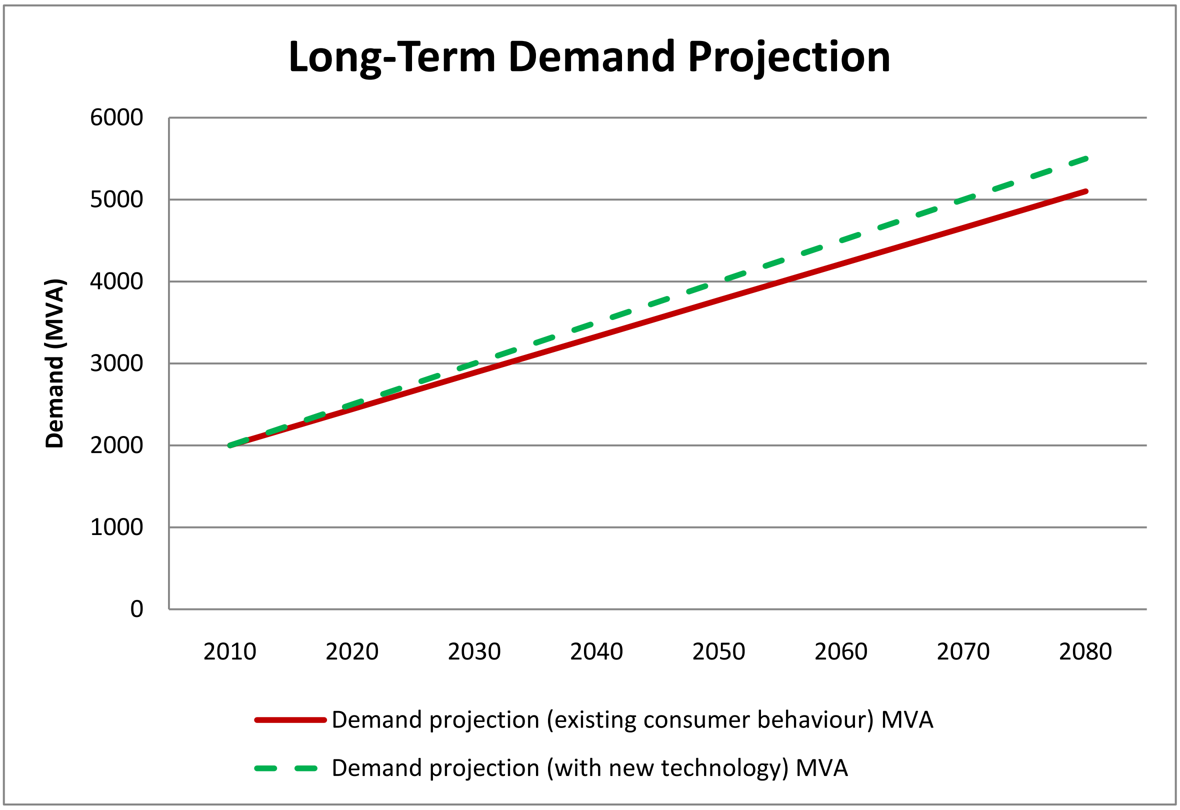


Figure 3-1 : Long-term demand projection[8]

[8] This projection assumes that the average load per ICP will remain relatively constant, which is in line with Vector's analysis of historical consumption patterns as well as expected future behaviour.

3.3.3 Network Architecture

Distribution network architecture can generally be described by two key attributes - voltage levels and network configuration. Reviews of the network architecture for Vector were carried out in 2003/04 (shortly after the merger of Vector and UnitedNetworks Ltd) and in 2007/08. The reviews looked at the appropriate voltage and configuration to be adopted for the development of the Vector electricity network. The following sections summarise the existing and future network architecture.

3.3.3.1 Voltage levels

The reviews concluded two voltage classes should be retained for the Vector network, namely sub-transmission and distribution voltages.

The sub-transmission system conveys bulk electricity around the network, connecting zone substations to each other and to the transmission grid exit points. Selecting the economically optimal sub-transmission voltage level requires a trade-off between capacity and construction cost. Higher voltage circuits can convey more power, but are more complex and expensive to create and maintain. The appropriate voltage level, therefore, depends on the size and density of loads.

The electricity distribution network distributes electricity from the zone substations to end-users. Given the extent of these networks, and the large number of connections made to them, distribution voltage levels have to be restricted (the cost of higher voltage assets and of connections to these networks is prohibitive). Again there is a trade-off between capacity and construction cost.

The key findings from the 2007/08 review were:

a. Sub-transmission voltage

Except for the very large loads (100MVA or above) with load centres at relative long distances (10km or further) from Transpower's GXPs, zone substations should continue to be supplied at 33kV. When used as sub-transmission network, 22kV circuits restrict bulk supply capacity to levels that are inefficiently low in high density areas like Auckland. Converting 22kV to 11kV is not an effective transformation ratio either.

The medium to long-term sub-transmission strategy is, therefore, to freeze further development of the existing 22kV sub-transmission network. When existing 22kV equipment reaches the end of their lives they will be replaced with 33kV rated equipment. Over time the 22kV will be uprated to 33kV.

The 66kV voltage level is comparable to 33kV as a sub-transmission voltage for the metropolitan parts of Auckland and might have been a good voltage choice if Vector had completely rebuilt the sub-transmission network. Not only is this impractical, given the very substantial investment in 33 kV assets, but a significant part of Auckland also still has a relatively low load density (and will remain so for a long time) which does not economically justify building higher-voltage sub-transmission networks. In addition, 66kV is a non-preferred (internationally) standard voltage that is gradually being phased out by electricity distribution businesses around the world.

For areas with large loads in a relatively confined area, or that are far from grid exit points, the preferred sub-transmission level is at 110kV. At present this only applies to the Auckland CBD and the main commercial area of the North Shore. The Auckland load density does not warrant sub-transmission at higher voltage levels.

b. Distribution voltage

The general distribution voltage level for the Vector network is at 11kV. The load density for most parts of Auckland does not warrant the use of 22kV for distribution, while distribution at lower voltage levels is even less cost-effective. The exceptions are:

- The Auckland CBD, where load density is significantly higher than the rest of the network and also where the area is supplied from the 110kV sub-transmission system. The latter factor makes 22kV distribution a natural choice as this would eliminate the need for an intermediate sub-transmission level; and
- In remote parts of the network where maintaining legal voltage limits is a challenge and uprating to 22kV is a practical and economic solution. Examples are the supply to Piha and Kaukapakapa.

The remaining 6.6kV distribution network in Ponsonby and Pt Chevalier is being uprated to 11kV.

3.3.3.2 Configuration

The review identified that the sub-transmission configuration is very different for the two regions making up the Vector network. However, the distribution configuration is generally very similar. The difference in configuration will also influence how the two regional networks are electrically protected and operated.

a. Southern region

The zone substations in the Southern region are typically supplied by two (and in rare occasions three) transformer feeders from GXPs. Typically there is no sub-transmission switchboard at zone substations. The power transformers at zone substations operate in parallel via the 11kV switchboards. From the distribution switchboards, distribution feeders emanate to supply the distribution network. The distribution feeders are configured in radial formation and are interconnected via normally open switches.

This configuration allows the zone substations to operate as separate, “closed” systems with the ability to back stop each other (take load from adjacent substations) through 11 kV feeders. The level of back stopping depends on the level of interconnectivity.

For the Southern network, there is a significant emphasis on supply security at the sub-transmission level. In the past the sub-transmission network was developed to provide sufficient redundant capacity to maintain supply under single contingency situations at all times, which is comparable to the practice of most Australian networks of similar size and demand characteristics. As a result of the sub-transmission configuration (no 33kV switchboards at zone substations), there is practically no interconnection between GXPs (nor is it possible). In the unlikely event of the loss of GXPs, load cannot be transferred across networks supplied from different GXPs.

Figure 3-2 below shows a typical network arrangement for the Southern region.

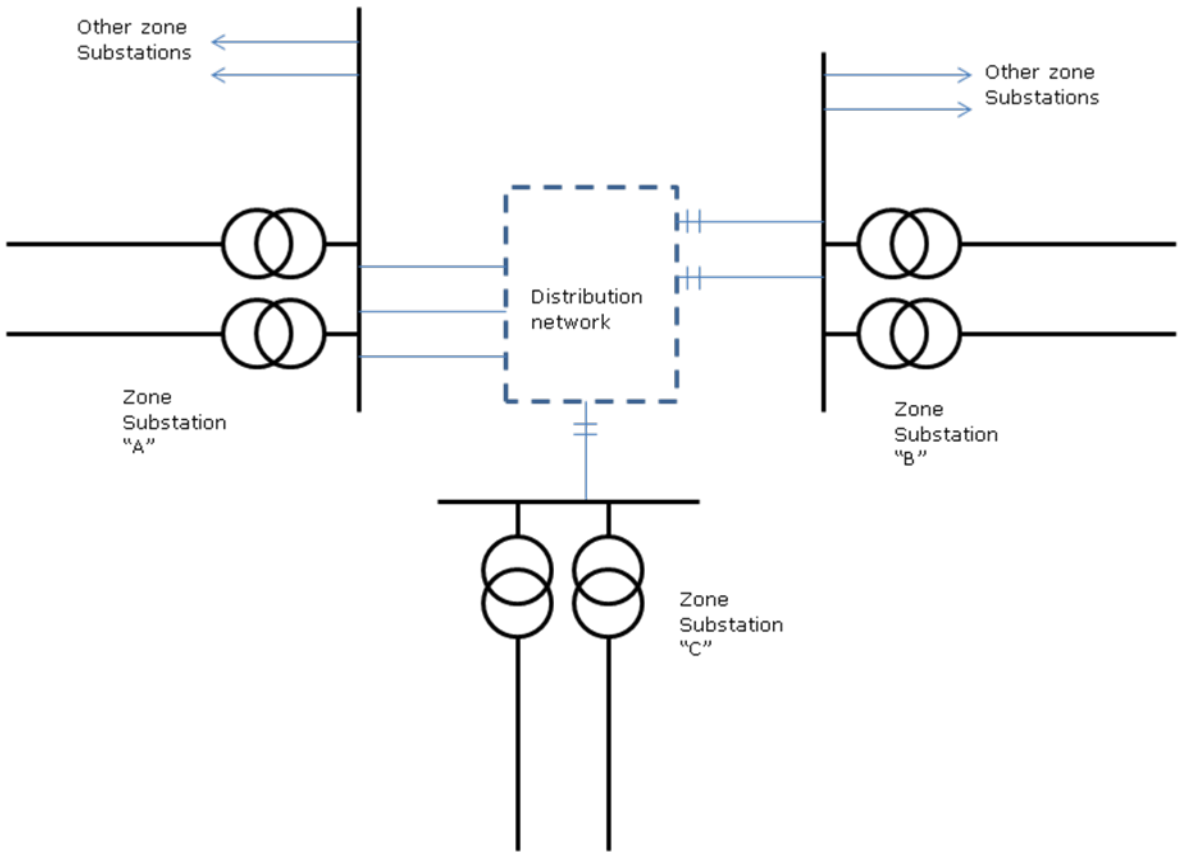


Figure 3-2 : Typical sub-transmission and distribution network arrangement for the Southern region

b. Northern region

The sub-transmission network in the Northern region is based on a mesh formation. A mesh network can be supplied by up to four circuits depending on the load the mesh is designed to supply and the geography of the area. Typically, only a single transformer is installed at the initial stage of development of zone substations. Supply security for the zone substation is provided by backstop capacity from the mesh sub-transmission network as well as from the neighbouring zone substations via 11kV feeders.

Where it cannot be economically justified to complete the mesh in full, which is often the case during earlier stages of development of an area, zone substations are fed from radial transformer feeders. At the next stage of development other legs of the mesh network are installed. When the mesh is formed, the feeders and power transformers are controlled by sub-transmission switchboards.

Meshed networks are especially suitable for low load density areas where demand for no break supply security is relatively low (for example, residential areas), as additional transformers and substations can be inserted into the mesh as and when the demand growth warrants (instead of having to install sub-transmission feeders from GXPs to zone substations). Also in the rural (long distance and low density) parts of the region, the network is typically constrained by voltage before capacity and security thresholds kick in. In these areas, use of smaller size zone substations and "shorter" feeders will help resolve voltage issues that may arise.

Figure 3-3 below shows a typical network arrangement for the Northern region.

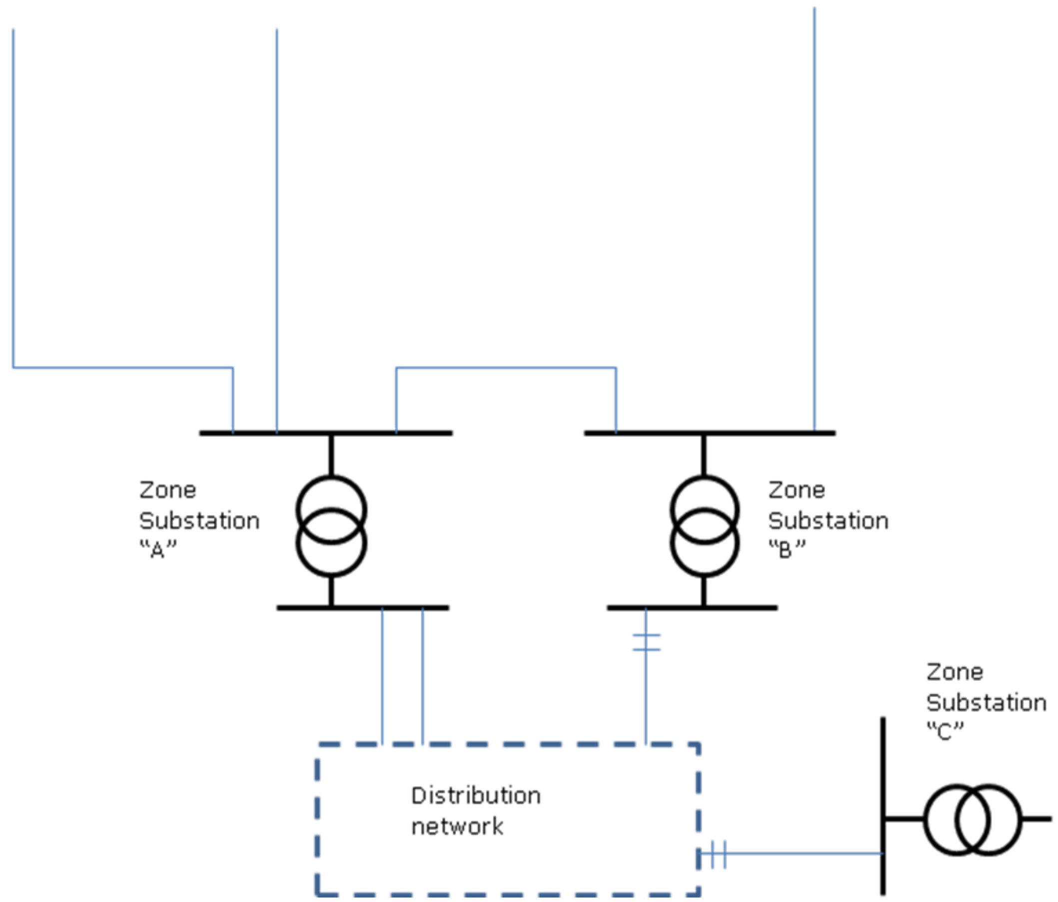


Figure 3-3 : Typical sub-transmission and distribution network arrangement for the Northern region

3.3.3.3 Radial vs Meshed configuration

The review identified that meshed sub-transmission networks are more economic if the GXP is off to the side of the supply area, whereas the economics tend to favour radial formations if the GXPs are closer to the centre of the supply area.

3.3.3.4 Electrical Protection

Protection schemes designed to serve radial systems are different from those designed for mesh systems, with the latter being substantially more complex and requiring a higher degree of fault-discrimination and ability for localised switching. As a result, the protection systems on the Southern network are simpler than those on the Northern and outages resulting from protection events tend to be less widespread, with shorter restoration times.

Vector's gradual upgrade from electro-mechanical relays to digital relays and further developments in the SCADA network (including RTUs) and communications systems, should over time enhance the ability of the Northern network protection systems and result in higher supply security levels.

3.3.3.5 Effects of Additional Load on Network Architecture

The network architecture reviews carried out in 2003/04 and 2007/08 concluded that the additional demand due to land development in the very long-term does not warrant a change to the existing network architecture (voltage and configuration).

The "Network Development Blueprint" projects completed in 2008/09 concluded that the architecture is sufficiently flexible to accommodate additional load to cater for the growth over the next 50 years through a combination of extension (additional substations and feeders) and increase utilisation of existing facilities. The additional load due to new technologies (200~480MVA) is relatively small compared to the long-term growth (~3000MVA) anticipated from additional customers. Change in network architecture is, therefore, not expected to be warranted in the foreseeable future.

3.3.4 Micro Grid

Vector does not consider that the way the regulatory regime is presently being operated provides incentives to improve supply quality above historical levels. There is also little evidence customers are prepared to pay extra for enhanced quality of service. As a result, there is little economic or financial justification to develop a full scale system of micro grids covering the whole of the Vector network from the perspective of improving network reliability. These systems also do not currently offer economically viable alternatives to standard grid connections.

It is, therefore, unlikely that there will be significant roll-out of micro-grids in the Vector distribution area in the near to medium-term future. The strategy for micro grid development will, therefore, likely be directed at particular situations, where over-voltage or reverse power flow arises from localised applications. These will be dealt with on a case-by-case basis.

3.3.5 Long-term Asset Investment Strategies

Electricity network asset investment decisions are typically made for assets with very long lives. Traditionally, while consumer and network technology remained relatively stable, investments could be made with a reasonable degree of certainty. However, the electricity market is currently entering a phase of change, with rapidly developing consumer applications and network applications following closely behind.

With the development of the future generation of smart home appliances, fast communications, more powerful computers, smart metering and network control systems, customer growth and demand patterns are becoming more uncertain. Some technologies are expected to increase demand while others will lead to reductions. Changes to consumption patterns (summer or winter peaking, morning or evening peaking) affects how the network is planned, operated and managed. Regulatory pressure (to limit return) and investor expectation (to increase return) is driving network companies towards more efficient use of assets and better management of risks.

The new generation of network technology also offers opportunities to enhance asset utilisation and reduce network risks. Initiatives such as network monitoring, remote control and automation are expected to be widely used to enhance the utilisation of the distribution network.

An important initiative that Vector has embarked on (with initial time-of-use tariffs) and which will be further developed in future is to review line charges to provide appropriate incentives to consumers to change their demand pattern, to achieve better utilisation of network assets.

Even in the face of the increased uncertainty about the future, new connections, network capacity augmentation and asset replacement investments remain essential. The following general asset investment guidelines have been adopted to ensure the potential impact of this is minimised (and to minimise the chance of assets being stranded in future):

- The network development strategy is to always aim at deferring investment where this would not breach safety or security standards, is practicable and economically efficient;
- Non-network solutions should always be considered as part of the mix of technological solutions and where feasible, should be embraced;
- Where network investment proves to be essential, smaller projects are preferred over larger projects (unless synergies of larger projects present a compelling financial advantage); and
- Unless customers desire higher levels of service, or regulatory incentives in this regard are created, our aim is to maintain the existing levels of service.

3.4 Evolution of the Smart Network

Worldwide there is an immense volume of literature, research and development being produced on the so-called "smart grid" (or smart network, from a distribution utility perspective). Inevitably, widely diverging views abound about what constitutes "smartness" in electricity distribution, and about the nature of future networks. While consensus has yet to emerge, there are a few common themes about the changes that make an evolution to smart networks possible, the main ones being[9]:

- the ability to access more real time information on the status of the network as a result of smart meters being rolled out and the falling cost of various network measuring and monitoring devices;
- two way communications – interaction between distribution devices such as meters, substations, electronic protection systems, switches and home area networks;
- the ability to provide far greater monitoring, automation, optimisation and fault responsiveness on the network;
- technological step changes associated with fibre optic communications and other information-based technology/next generation telecommunications; and
- integration of power systems infrastructure with information and communication systems.

In their recently released "Transmission Tomorrow" document, Transpower provides a definition of smart grids[10] that resonates well with Vector's view on the same:

> *"...an electricity network that can intelligently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies."*

While there are undeniably many exciting developments underway offering various opportunities for enhancing the operation of electricity distribution networks, Vector is somewhat sceptical about the excessive "hype" that seems to surround many discussions on smart networks. Many applications that are now widely being touted as "smart" have already been successfully adopted by Vector (and others) in the past.[11] Vector prides itself on having been "smart" in the past as well and does not see smart networks as a new development, a new type of asset, or a sudden step-change in behaviour. In our view it is rather a further evolution in the long history of distribution networks.

---

[9] These definitions were adapted from a draft of a document developed by the Electricity Networks Association, titled *"The business case for EDBs to develop smart networks"*, 29 October 2010.

[10] Transpower publication titled "Transmission Tomorrow", p28, undated.

[11] This includes automation of substations, automatic load sharing between adjacent substations, bus-automation, asset condition and status monitoring etc.

We see the potential benefit from the evolving smart network technology to distribution utilities mainly in the opportunities that these provide in:

- supporting an efficient asset investment response to an ongoing increase in electricity demand, by increasing the utilisation of existing assets and by better managing peak demand through more effectively spreading the use of electricity[12];
- providing customers with better means of controlling their use of electricity and utilities with the means of conveying effective price signals to customers to encourage this efficiency;
- supporting the safe uptake of increasing levels of distributed generation and two-way energy flows in distribution networks[13];
- improving network reliability through increased automation and flexibility, as well as the ability to rapidly pinpoint fault locations; and
- improved asset management resulting from increased levels of asset performance information.

Vector is keeping fully abreast of the continuing evolution of smart applications in distribution networks. However, we note the following:

- Under current regulatory arrangements (in spite of the intent of Section 54Q), it is not clear that a strong business case can be made in the New Zealand regulatory environment for major investment in many of the more attractive features of smart networks, specifically where these are intended to improve network reliability and response to outages.[14] These applications include self-healing networks, widespread use of fault locating devices, etc;
- The excessive degree of "hype" that still surround smart networks and the lack of consensus on technology standards or the manner in which various applications will interface leads us to believe it is more appropriate to at this stage focus on particular applications where we see direct economic value, but to still retain a wait-and-see attitude towards a wider investment in smart technologies; and
- At present, the prime benefit of adopting "smart" applications to Vector is the ability it offers to allow network capacity increases to be deferred, by increasing the utilisation of network assets, or by shifting load demand peaks.[15] However, in general the structure of the New Zealand electricity market does not support a sound business case for these investments. This is because the full cost involved with the solutions lie with the distribution utility but it can only realise a portion of the downstream benefits realised. The rest of these benefits accrue to the transmission system provider and to the electricity generators. In theory contractual agreements between the parties could allow a portion of these wider system benefits to be captured by the investing party, but this has not been a common occurrence in the industry to date.

Taking this into account, Vector has thus far continued on its historical evolution path for smart technologies rather than committing itself to a large-scale adoption and roll-out of any of the "smart network" technologies. Vector has over the last year conducted substantial research into smart applications. This has been to keep abreast

[12] This spreading could be over time, reducing peak demand, or by spreading load over adjacent assets.

[13] This occurs when customers sell electricity back into the grid.

[14] There is no certainty Vector will be able to recover its investment in applications intended predominantly to improve network reliability or efficiency.

[15] Shifting load peaks means more growth can be accommodated before Vector's network security standards are compromised.

of developments and to ensure Vector's asset investments are capable of being effectively integrated in future smart networks. Vector has also trialled certain promising new technologies (where there are direct network and economic benefits) on the network including:

- Testing and developing the interface of various intelligent data-collection devices (including smart meters in distribution substations) with the existing communication and data capturing systems;
- Assessing the use of information provided by the data-collection devices to support load shifting schemes, network automation, allow better asset utilisation and/or allow revisions of Vector's network planning parameters;
- Testing retro-fitting applications on existing switches that will allow remote control, or automatic switching; and
- Implementing a novel new method to address fault-level issues at zone substations by allowing split-bus operation, without impacting on reliability.

The outcome of these trials was generally highly positive and Vector will continue with research and testing applications during 2011. In addition, a small-scale roll-out of data-collection and automatic switching devices on various points on the network is planned for 2011. This will be at positions where significant potential for shifting load between adjacent substations has been identified,[16] at representative locations on the network, to collect more exhaustive information about load behaviour and asset utilisation on a distribution level (including low voltage), and at positions where automated switching devices could materially contribute to improving the service for particular groups of customers.

Other evolutionary steps planned for 2011 include:

- Increased cooperation with Transpower and other North Island distribution utilities to implement a load aggregation scheme, and preparing the Vector network for supporting this;
- Implementing a protocol to allow direct real-time electronic information sharing between Transpower and Vector at GXP level; and
- Further development of our information technology capability to accommodate the anticipated exponential increase in data collection and processing capacity associated with evolving smart networks, and integration of our existing IT applications.

3.5 Demand Management

3.5.1 Business Reasons for Managing Demand

Managing demand at premises provides a viable alternative to building network assets. From a network management point of view, demand management is able to be utilised to achieve the following:

a. Load levelling

By reducing demand during peak periods, there is potential to reduce or avoid network capital expenditure. Reduction of peak demand can be achieved either by moving load from peak times to off peak times (e.g. hot water heating) or by reducing demand through energy efficiency (eg. energy efficient lighting).

[16] Zone substations with significantly different load profiles can offer opportunity for load shifting at different times of the day, thereby deferring the need for reinforcement.

b. **Network Fault Management**

During a network fault, demand reduction allows more load to be transferred from one area of the network to another, thereby reducing the number of customers experiencing a loss of service.

c. **Manage High Penetration Levels of Solar PV (Future)**

With predicted increasing penetration of grid connected solar PV, managing demand provides a potential method of mitigating potential network issues, especially with regard to voltage.

3.5.2 Changing Requirements

Historically, Vector has managed demand through the use of ripple and pilot wire control of hot water cylinders. While reasonably effective, there are several technology changes which provide challenges and opportunities that may lead to alternative demand management solutions.

Heat pumps

A predicted significant increase in heat pump uptake in Auckland will likely result in a new network peak loads on hot days in summer (when the heat pumps are used for cooling).

Network initiated management of heat pumps, either through thermostat adjustment, cycling on and off or preheating, is a potential alternative to investing in additional network assets (in conjunction with providing attractive price signals to customers).

Electric vehicles

It is expected that electric vehicles will become available in the New Zealand market from 2013, and will see an exponential increase in uptake over the next 15 years.

Battery charging during existing peak periods will place significant increased demand on the network. Charging management which moves as much charging as possible to off-peak periods may be a desirable alternative to network investment.

In addition, future electric vehicle developments will likely include the ability to feed back into the network from the car batteries. Appropriate communication and control systems will need to be in place to allow this to be managed effectively.

Solar PV / Battery Storage

Reducing prices of solar PV together with increased cost of grid electricity may see increase of distributed generation levels on the network. If combined with battery storage, these systems provide the ability to reduce premise demand.

Smart meters

Smart meters provide a foundational capability for new demand management options. At a base level the meters provide the capability to introduce time related charging methods to incentivise customers to change consumption patterns.

In addition, smart meters provide two way communication capabilities which may be utilised to communicate with appliances at the premises (see below).

Smart appliances

Manufacturers are working to include communication capability in appliances such as heat pumps, dishwashers, refrigerators and washing machines. This capability will allow signals from smart meters or home communication hubs to control the operation of the appliance to reduce energy use at critical times e.g. by pausing operation or adjusting temperature settings. Smart appliances are expected to become increasingly available in the market in two to three years.

LED lighting

Residential lighting accounts for a significant portion of peak demand (15-20%). While compact fluorescent options have been available for some time to replace existing incandescent and halogen bulbs, these have not been popular with consumers. LED bulbs will be widely available in 2012 and offer energy savings, good light quality and exceptionally long life.

Fibre to the Home

The government fibre initiative will provide a fast communication option to many Auckland homes. This will provide a valuable communication option for future demand management systems.

3.5.3 Demand Management Strategy

Currently ripple control of hot water cylinders provides the most reliable and cost effective method of demand management. As described above, however, technology changes provide an increasing number of opportunities for demand management, and ripple control or pilot wire technology will likely not be the best future option.

While there are levels of uncertainty regarding timings and uptake rates of a number of the technologies discussed above, it is important that Vector's demand management strategy keeps future options open. The following summarises the approach to be taken.

- Focus on demand management solutions in areas of the network where there are constraints, rather than network wide initiatives;
- Utilise existing ripple and pilot wire investments to maximum value, but do not significantly invest in extending or upgrading these systems across the network;
- Consider options to reduce demand with solutions that provide customer energy savings. (Continue with input into regulatory review processes related to clause 54Q of the Commerce Act 1986 to ensure the financial viability of these options);
- Evaluate options to incentivise a change by customers of energy use through pricing structures; and
- Conduct field trials of emerging leading demand management technologies (home energy management hubs and associated control systems).

Vector

Electricity
Asset Management Plan
2011 – 2021

Service Levels – Section 4

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

4. Service Levels

This section describes the Electricity Distribution Business' performance targets set under Vector's asset management strategy. Performance against these targets is also discussed.

Following commissioning of a Technical Asset Master (TAM) register late in 2010 (see Sections 6 and 7 for further discussion on this), Vector is now collecting more disaggregated asset performance data. This will be incorporated in an extended set of asset-based performance measures that will form part of future AMPs.

4.1 Consumer Oriented Performance Targets

Vector is committed to providing a high standard of service and a safe, reliable and secure electricity supply. This challenge requires effective and efficient network solutions to enable Vector to meet this goal with the optimum investment. As such, Vector recognises communication is essential in order to improve and understand what services and products our customers like, what they do not like and what they need.

Customers are widely consulted and are able to provide feedback about their expectations through a variety of contact points:

- Call centre representatives;
- Customer service team representatives;
- Operations and project representatives;
- Service provider/contracting representatives;
- Customer service feedback surveys;
- Customer engagement surveys;
- External publications and websites; and
- Dedicated account management for the very large customers.

4.1.1 Customer Expectations

Keeping engaged and aligned with changing customer expectations is fundamental to optimal asset investment and asset management practices.

Individual customers have different and diverse needs and expectations around supply reliability. For some, interruption frequency is a key consideration. For others, the duration of interruption has real consequences.

In terms of individual requirements, the most significant feedback comes from customer surveys. The results of these surveys provide a basis for setting customer service levels, by drawing out customer preferences around the reliability of supply in terms of outages and duration of outages, and the extent to which customers would be prepared to pay for improved reliability.

Results from the 2006 and 2008 surveys are summarised in Table 4-1 below. Both surveys were undertaken by computer assisted telephone interviewing (CATI). Participants were identified as the "person most responsible for making decisions relating to electricity".

Customer Survey Date	Mar 2006		Jan 2008	
Residential category	Urban	Rural	Urban	Rural
Sample size	1183	958	829	671
Satisfied with the value for money regarding their electricity supply	81%	70%	79%	70%
Rate the current service provided by Vector as adequate or better	84%	74%	91%	79%
Believe they have experienced less than 3 outages over 12 months	74%	37%	74%	32%
Believe they have experienced less than 6 outages over 12 months	92%	68%	89%	61%
Rate the frequency of outages experienced to be acceptable	77%	58%	71%	50%
Do not wish to pay an additional amount for fewer outages	79%	85%	85%	82%
Do not wish to pay an additional amount for NO outages	82%	84%	84%	85%
Consider a maximum of 3 outages per annum to be acceptable	76%	76%	81%	72%
Believe the last outage they experienced was less than 3 hours	55%	67%	58%	48%
Believe the last outage they experienced was more than 3 hours	10%	16%	23%	33%
Rate the duration of the last outage experienced to be acceptable	68%	49%	63%	49%
Do not wish to pay an additional amount for shorter duration outages	85%	87%	90%	89%
Consider a 30 to 60 minute outage to be acceptable	43%	30%	56%	61%

Table 4-1 : Summary of 2006 and 2008 survey results

In summary, the feedback received from the most recent engagement survey continues to validate the following general preferences:

- Most customers rate the service provided by Vector as adequate or better;
- Most customers are highly satisfied with the value for money experienced regarding their electricity supply; and
- Most customers express no desire to pay an additional amount to receive a service with reduced number of outages or reduced duration of outages.

No clear opinion is apparent from the surveys regarding the acceptability of the number or the duration of outages experienced.

In addition to these surveys, Vector's larger scale engagements tend to focus on councils and community groups.

4.1.2 Customer Service

4.1.2.1 Vector's Customer Service Commitment

Vector has a target set of customer service levels. If these are breached, customers are entitled to a compensatory payment (see Section 4.1.7).

The service standards are specific to the customer/retailer relationship model adopted on the various parts of our network, as indicated in Table 4-2 below.

Vector Target

Customer/Retailer model	Conveyance (Southern)				Interposed (Northern)	
Service level type		CBD / Industrial	Urban	Rural	Urban	Rural
Maximum interruption frequency (per year)		4	4	14	4	14
Maximum interruption duration (hours)		2.5	2.5	3	3	6

Table 4-2 : Vector's service targets

Note that incidents arising as a result of generation and transmission bulk supply failures, or of extreme events (see Section 4.1.6) are excluded from this scheme. While Vector will respond to breaches in terms of the service commitment when they come to its attention, in some cases this may require notification by the affected customer.

Figure 4-1 is a map indicating performance against customer service thresholds, at the distribution transformer level, for outage duration based on the 12 months to the end of December 2010.

Figure 4-2 shows performance against outage frequency thresholds based on the same period.

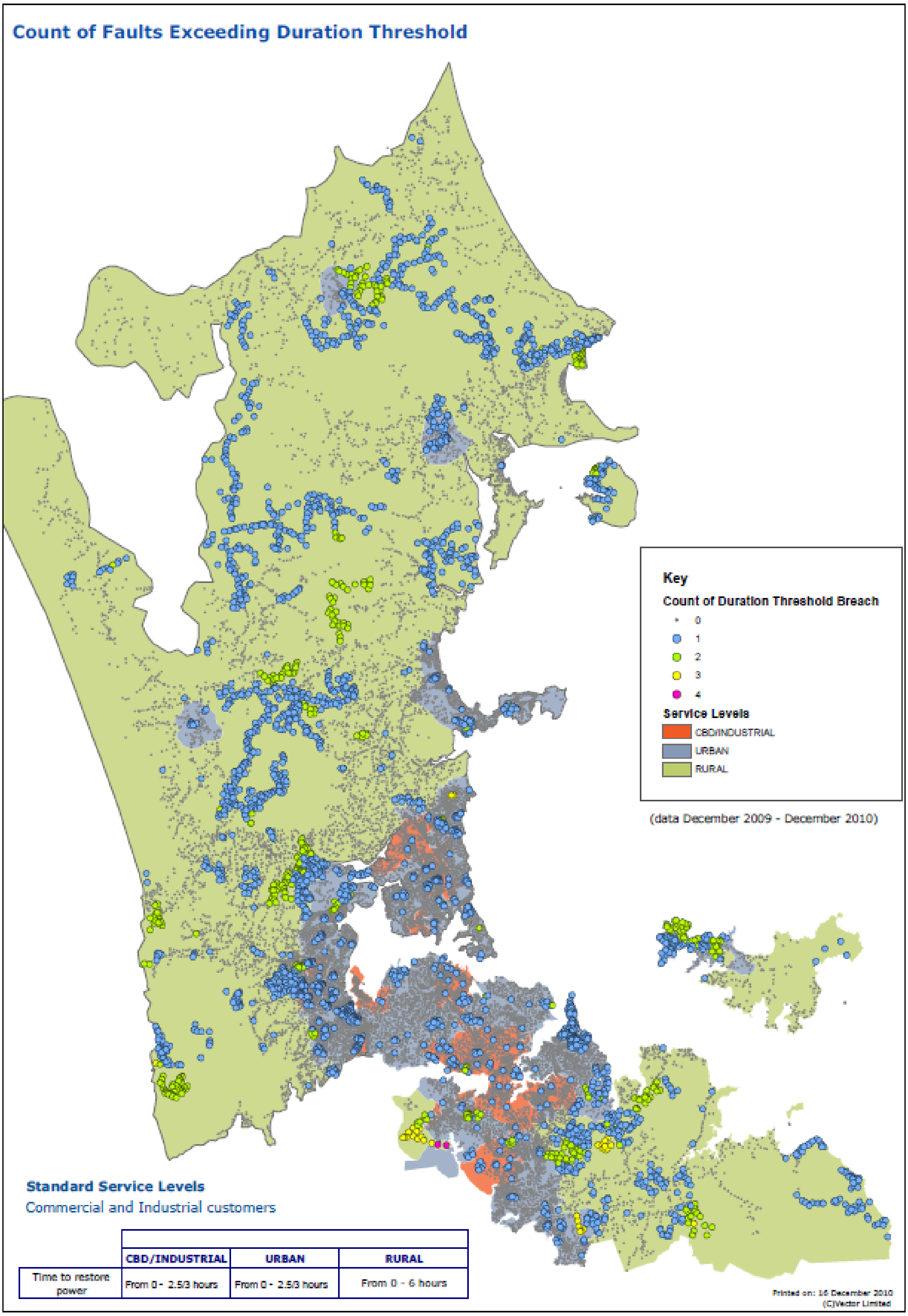


Figure 4-1 : Count of faults exceeding duration threshold

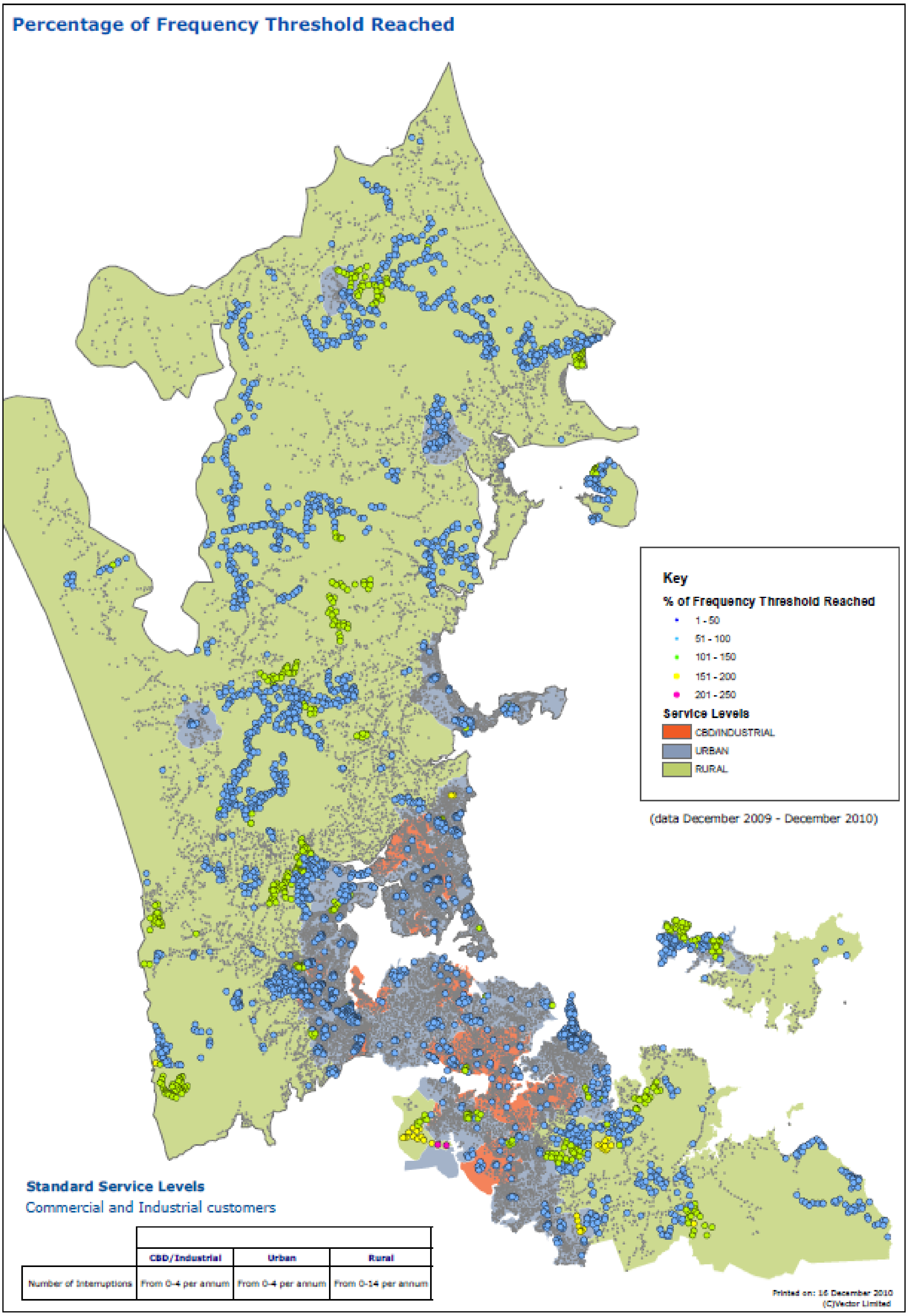


Figure 4-2 : Count of faults exceeding frequency threshold

4.1.2.2 Customer Feedback

Vector obtains feedback from Customer Service Monitors, through which we contact a sample of customers who have initiated contact with Vector through our faults process or customer services team.

The survey is divided into a number of sections:

- Overall satisfaction with Vector;
- Satisfaction with the Call Centre (Telnet) for Key Performance Indicator (KPI) purposes; and
- Satisfaction with Vector's Field Service Providers' (FSPs') Service Technician for KPI purposes.

It also includes some branding questions and reliability expectations and occasionally includes a few extra questions about relevant topics we seek the customer's opinion on.

The Call Centre and FSP Service Technician performance scores are divided by region and also further divided by FSP if required. Vector uses this data for monthly performance measures for FSP and Call Centre contracts.

Vector Target

Targets for the Contracting Partners and Call Centre are 85% whilst the target for the Vector overall score is currently 83%.

Figure 4-3, Figure 4-4 and Figure 4-5 show the historical overall customer satisfaction trends against target by region, the call centre satisfaction against target by region and the service technician satisfaction against target by region.

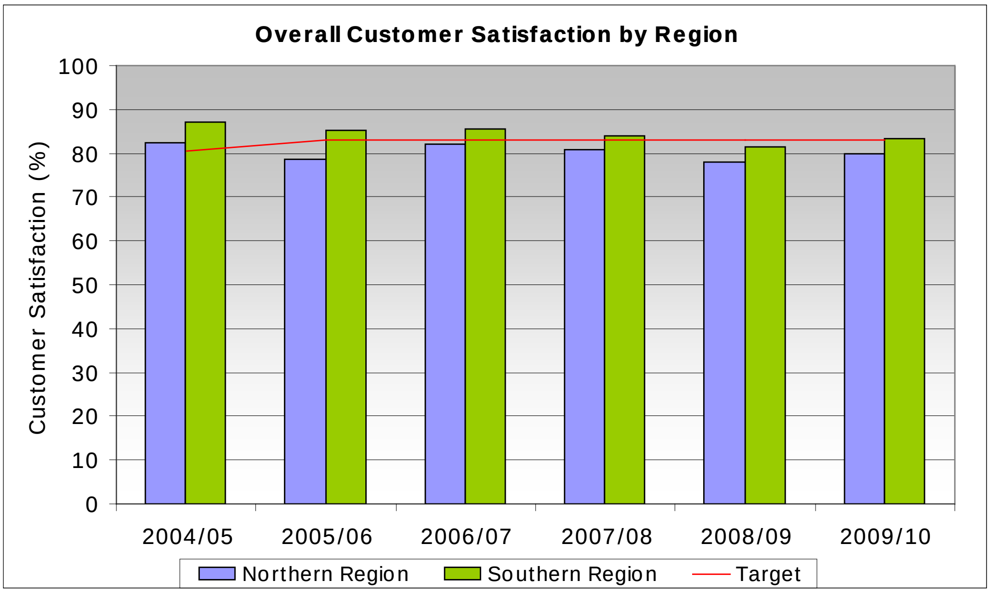


Figure 4-3 : Vector's service targets

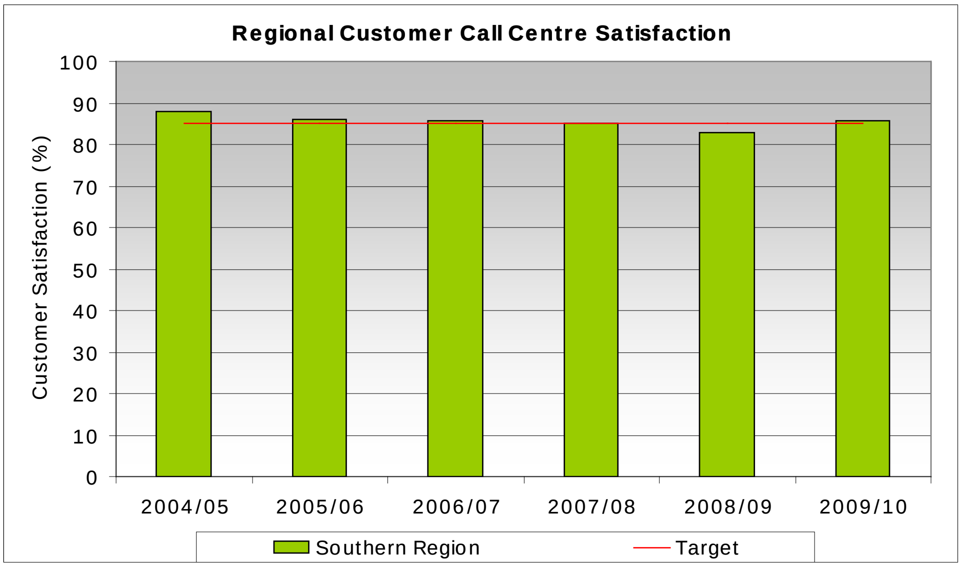


Figure 4-4 : Customer call centre satisfaction

Note: Only Southern region results are shown as the Northern region's interposed use-of-system agreements with energy retailers means that customers do not have direct contact with Vector's call centre.

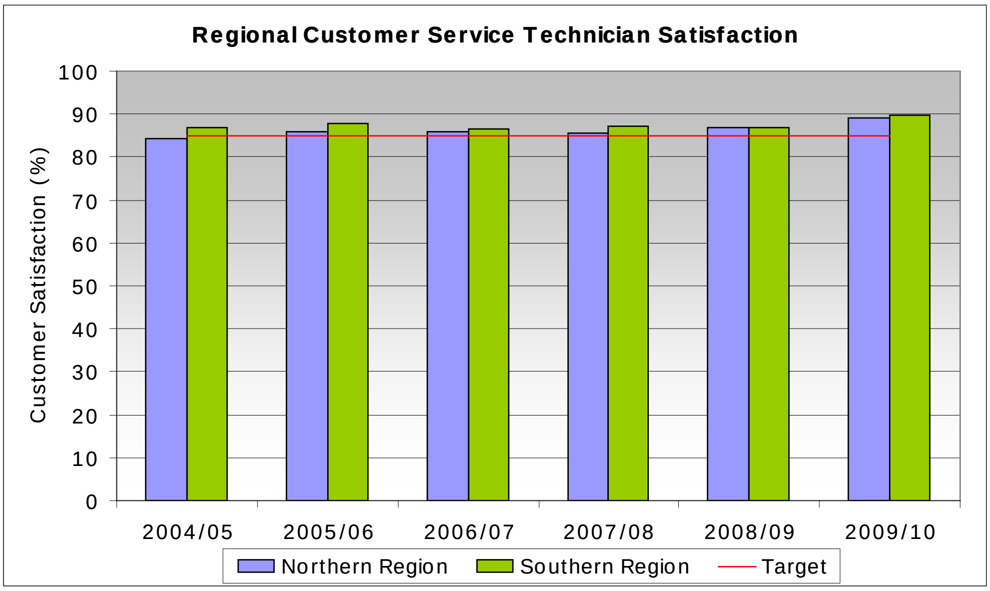


Figure 4-5 : Customer service technician satisfaction

Note that Vector continues with two different business models for customer interaction based on existing use-of-system agreements with energy retailers. In the Southern region customers contact Vector directly for fault and general enquiries around pricing and service. In the Northern region the customer interaction is managed via the customer's energy retailer. Customers contact Vector directly across all networks with tree enquiries, mapping requests and any connection requests around network assets.

Customer satisfaction is better where there is direct contact.

4.1.3 Customer Complaints

4.1.3.1 Overall Approach

Although Vector seeks to provide a high standard of service and a reliable electricity supply, there may be times when customers have concerns with their service. In these instances, Vector's Customer Services team is ready to take appropriate actions to manage these concerns, log all reported compliance in relation to the distribution network and coordinate closely with all appropriate areas of the business in resolving complaints and improving the customer experience.

If the cause for concern or complaint is not immediately resolved, it is logged as a formal complaint with our Customer Services team. The Customer Services team is responsible for complaint resolution, identifying trends and raising issues with the appropriate business units in order to implement permanent solutions and prevent recurrence, where appropriate.

Vector adheres to a formal complaint resolution process. Vector's preference is for proactive, consultative and direct engagement with customers via the Customer Services team. Engagement takes the form of attending community meetings and meeting with customers or customer representatives to present and discuss areas of concern. A significant number of these discussions are related to supply quality issues. This provides Vector the opportunity to explain historical and current supply quality performance, listen to and understand customer concerns and consult on appropriate actions and future recommendations.

Vector's formal complaint process is as follows:

- Acknowledgement of receipt of the complaint by Vector (see timeframe below);
- Keeping the customer informed with progress in addressing the complaint;
- Attempting to resolve the complaint within the timeframes specified by the Electricity and Gas Complaints Commission (EGCC, see below); and
- If the complaint is not resolved within the specified timeframes, informing the customer of the reason for the delay and working towards resolution.

If we have not resolved the complaint within the specified timeframes then the customer is advised of the option of contacting the EGCC.

4.1.3.2 Response Times

Vector attempts to resolve customer complaints to everyone's satisfaction as quickly as possible. Vector's response time target is to resolve >90% of complaints within the prescribed timeframes. We have two internal targets for complaints:

- Southern region (and other customers who contact Vector directly):
  - Acknowledgement in two working days; and
  - Resolved in ten working days.
- Northern region (where the complaint comes via a retailer):
  - Response to retailer in five working days.

Vector's Customer Services team is responsible for achievement of these targets and is incentivised via Vector's KPI programme.

Vector Target

Vector's response time target is to resolve >90% of complaints within the prescribed timeframes.

For the 2009/2010 Year 2,043 customer complaints were received, of which 1,964 (96%) were resolved in time.

These targets are tighter than the industry targets under the EGCC, which stipulates that complaints must be resolved within 20 working days, or 40 working days for complex cases.

4.1.3.3 Customer Complaints – EGCC Complaints

The EGCC is an independent body that facilitates resolution between the electricity company and the consumer if the other means of resolution have failed. All customers have the option of contacting the EGCC directly if their complaint has not been resolved to their satisfaction.

In the 2009/10 year, 26 (1.3%) complaints went to the EGCC, of which 20 were resolved under Vector's standard resolution process.

The remaining six complaints required interaction with the EGCC with the following outcomes:

- Two were resolved by settlement;
- One was withdrawn by the customer;
- One went to Notice of Intention and was upheld; and
- Two are currently in the resolution process.

4.1.4 Call Centre Performance

Vector has two main call centre lines managed by Telnet: the 24/7 Faults Line (0508 VECTOR) and the General Enquiries line (09 303-0626) which is available 7am to 6pm, Monday to Friday.

Vector Target

Service Level Agreements (SLAs) are set as follows for each line based on time to answer a call:

- Faults Line:

  80% of calls answered within 20 seconds on 80% of the days of the month.
- General Enquiries

  80% of calls answered within 20 seconds on 90% of the days of the month.

The SLAs reflect the fact that the faults line has a highly variable and unpredictable call volume.

Telnet is incentivised to achieve these targets through Vector's KPI programme. Figure 4-6 below shows actual response times compared against the targets for both types of enquiries.

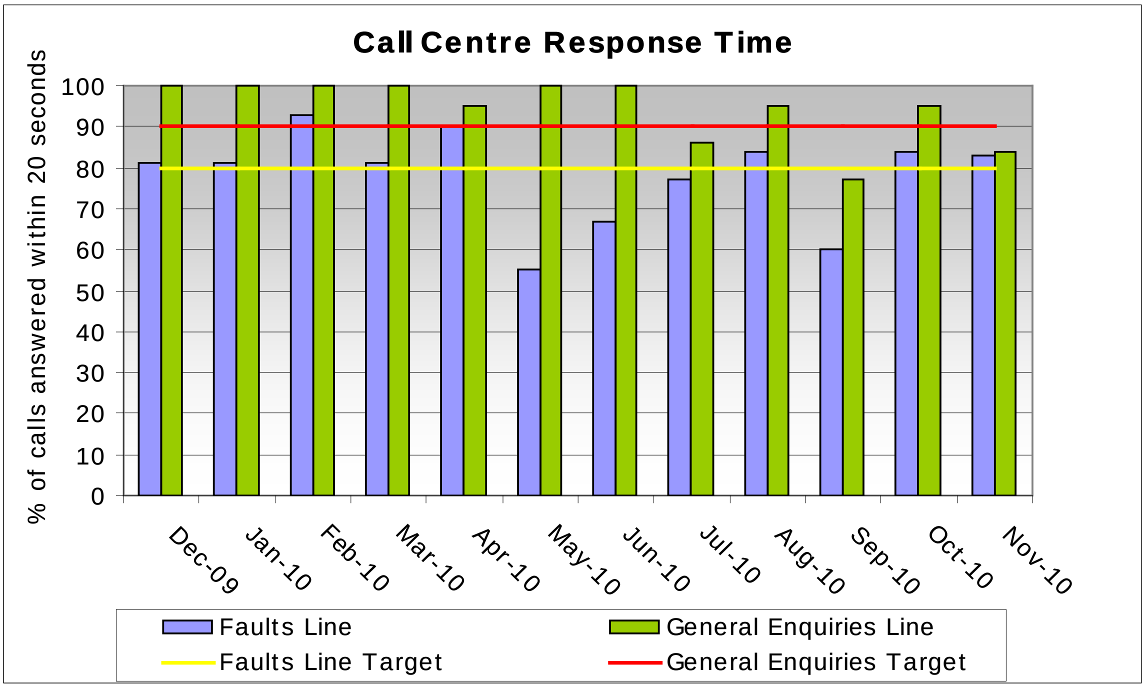


Figure 4-6 : Call centre response time

Response time has generally been above target except in the early months of winter (May and June) and September. Poor weather and the marked increase in faults had an impact in response during those months. Fault call volumes are very unpredictable so Vector's aim is to provide better information automatically to customers reducing the need to have a 'human' voice available to talk to each customer that calls. This allows Vector to provide information to customers quickly in area outage situations and ensures the call centre lines remain free for customers with important calls regarding emergencies and safety issues to get assistance from a call centre agent.

Work has started on a review of Vector's current messaging service to improve the speed with which it can upload messages. With the increased use of internet capable phones and remote access laptops, information updates on our website have also become a popular method for a number of customers to access outage information in more widespread outage situations.

4.1.5 Supply Quality Standards

Vector's supply quality objectives are focused on ensuring the required service levels are achieved and maintained in accordance with its published customer expectations and regulatory requirements. In this context supply quality refers to the magnitude, shape, phase and frequency of the supplied voltage waveform. Vector's supply quality targets are highlighted below.

Vector Target	
Supply Quality Parameter	**Standard**
Voltage at point of supply (single phase 230V	± 6%
Voltage at point of supply (three phase 400V)	± 6%
Frequency of supply (50 Hz)	± 1.5%
Total Harmonic Distortion (of supply voltage) NZECP 36	≤ 5%

Electricity distribution networks remain subject to supply quality disturbances, the most typically observed phenomena being momentary voltage sags.

The source of these disturbances can be highly localised, affecting few customers, or could be generated from distant locations that permeate throughout the supply network. It is impossible to guarantee a perfect power supply free from voltage sags, or other quality of supply issues such as voltage surges or harmonic distortion.

The number of disturbances experienced by any individual customer depends largely on the geographic location of their power supply network. Vector's CBD supply area is served by underground cables and is less exposed to disturbances. Rural or outlying suburban areas typically served by long overhead lines are more susceptible to environmental factors and third party interruptions and are subject to a greater number of disturbances.

Vector's focus is on understanding the cause and effects and dealing with these on a case-by-case basis. Long-term harmonic distortion trends are also monitored at various positions on the network to provide early warning should distortion levels approach maximum acceptable levels. In some areas counter measures have been implemented, such as the installation of Neutral Earthing Resistors (NERs) and enhanced protection schemes.

4.1.5.1 Momentary Voltage Sags

Momentary sag is defined as any recorded event measured at the 11kV zone substation bus which falls below 80% of nominal voltage, regardless of the event's duration. These momentary sags are typically associated with faults on and around the Vector network along with transmitted disturbances from the national grid.

Vector has established supply quality service standards, as shown below, that reflect the different experience and expectation of supply quality of different customer groups, and recognises that business customers have a higher reliance on disturbance-free supply.

Vector Target	
Location	**Target (sags per year below 80% of nominal voltage)**
CBD	≤ 20
Industrial	≤ 20
Urban	≤ 30
Rural	≤ 40

Vector has been proactively monitoring momentary voltage sags at the zone substation 11kV bus level since 2004, and now includes 55 Power Quality Monitors (PQMs) located at zone substations covering Auckland CBD, industrial, urban and rural locations (plus four mobile units).

The following Table 4-3 provides a summary of compliance to the published service standards disaggregated by various customer locations.

Zone Sub	Location	2005	2006	2007	2008	2009	2010	Target
Quay	CBD	17	6	26	11	29	3	≤20
Victoria	CBD	13	8	16	9	6	-	≤20
Carbine	Industrial	6	6	18	7	10	6	≤30
McNab	Industrial	9	5	14	5	-	16	≤30
Rockfield	Industrial	8	11	13	4	12	5	≤30
Rosebank	Industrial	10	8	17	14	13	12	≤30
Wiri	Industrial	10	20	15	13	18	6	≤30
Bairds	Urban	17	20	39	25	27	9	≤30
Howick	Urban	6	22	22	12	20	2	≤30
Manurewa	Urban	15	15	23	33	22	9	≤30
Otara	Rural	8	35	25	17	17	8	≤40
Takanini	Rural	22	25	26	28	23	31	≤40
Oratia	Rural	-	-	-	-	-	32	≤40
Hillcrest	Residential	-	-	-	-	-	18	≤30
East Coast Bays	Residential	-	-	-	-	-	4	≤30
McKinnon	Commercial	-	-	-	-	-	7	≤20
Westfield	Industrial	-	-	-	-	-	0	≤30
St John[1]	Residential	-	-	-	-	-		≤30
Red Beach	Residential	-	-	-	-	-	12	≤30
Remuera	Residential	-	-	-	-	-	16	≤30
Orakei	Residential	-	-	-	-	-	4	≤30
Greenmount	Industrial	-	-	-	-	-	4	≤30

Table 4-3 : Summary of compliance to the published service standards

[1] St Johns is a newly commissioned zone substation with data for only the last quarter. Annual sag count, therefore, was not recorded.

Typical responses to non-compliance to service standards include targeted maintenance (such as vegetation control), network inspections (such as thermal imaging to detect hot spots and weak links), asset renewal/replacement and protection upgrades (including the installation of additional monitoring and/or protection equipment

St Johns is a newly commissioned zone substation with data for only the last quarter and hence of little value. Annual sag count therefore was not recorded in Table 4-3 above.

The Victoria Zone Substation had the Voltage Transformer (VT) disconnected from the power quality meter for multiple periods throughout the year. The data collected between outages is not considered to be reliable so has been excluded from this report.

4.1.5.2 Harmonic Distortion

The PQMs also track Total Harmonic Distortion (THD) measured at the 11kV zone substation bus. Excessive THD can adversely affect the expected lifetime of some of Vector’s network assets (such as transformers) as well as customers’ plant and equipment and may cause sensitive electronic or IT equipment to fail.

The causes of THD may be specific (in the case of an electrically “noisy” or non-linear large industrial load) or dispersed (as in the increasingly widespread use of equipment with electronic power supplies and fluorescent lamps). Table 4-4 shows mean THD calculated as a percentage value on an hourly basis.

Zone Sub	Location	2005	2006	2007	2008	2009	2010	Target
Quay	CBD	1.3	1.5	1.6	1.6	0.7	1.0	≤5.0
Victoria	CBD	2.0	1.7	1.6	1.4	0.7	-	≤5.0
Carbine	Industrial	3.2	3.4	3.6	3.5	2.2	2.1	≤5.0
McNab	Industrial	1.0	0.9	1.1	1.6	0.9	0.8	≤5.0
Rockfield	Industrial	2.8	2.9	3.1	3.2	2.9	2.7	≤5.0
Rosebank	Industrial	3.2	3.1	3.5	3.3	2.0	2.0	≤5.0
Wiri	Industrial	1.9	2.0	2.2	2.1	1.2	1.6	≤5.0
Bairds	Urban	1.5	1.5	1.6	1.9	1.3	1.2	≤5.0
Howick	Urban	2.5	2.5	2.6	2.9	2.3	2.2	≤5.0
Manurewa	Urban	3.2	3.1	3.4	3.7	2.6	2.5	≤5.0
Otara	Rural	1.4	1.2	1.4	2.2	1.4	1.3	≤5.0
Takanini	Rural	2.7	2.7	2.6	2.7	1.7	1.6	≤5.0
Oratia	Rural	-	-	-	-	1.4	1.5	≤5.0
Hillcrest	Residential	-	-	-	-	2.1	2.0	≤5.0
East Coast Bays	Residential	-	-	-	-	2.5	2.4	≤5.0
McKinnon	Commercial	-	-	-	-	1.7	1.7	≤5.0
Westfield	Industrial	-	-	-	-	-	0.9	≤5.0
St John	Residential	-	-	-	-	-	1.4	≤5.0
Red Beach	Residential	-	-	-	-	-	2.2	≤5.0
Remuera	Residential	-	-	-	-	-	2.0	≤5.0
Orakei	Residential	-	-	-	-	-	2.0	≤5.0
Greenmount	Industrial	-	-	-	-	-	1.5	≤5.0

Table 4-4 : Mean THD calculated as a percentage value on an hourly basis

THD for most sites have remained fairly constant year on year with no significant changes.

Vector's objective is to have PQM coverage at all zone substations over the next ten years, in order to gain a comprehensive understanding of the causes and impacts of power quality (PQ) issues. The necessary measuring devices are being progressively installed over the planning period and all new zone substations will be equipped with PQ meters.

4.1.6 Supply Reliability Performance

Vector's strategic goal is to ensure supply reliability performance targets are achieved in accordance with regulatory thresholds and customer expectations.

Targets and measures for overall network reliability are defined by the regulatory requirements; whereas Vector's standard service levels consider individual supply reliability expectations.

In the context of average network supply reliability, both the frequency and duration of interruptions are recorded and reported through the following internationally recognised measures:

- SAIDI (System Average Interruption Duration Index): the length of time in minutes that the average customer spends without supply over a year; and
- SAIFI (System Average Interruption Frequency Index): the number of sustained supply interruptions which the average customer experiences over a year.

Both SAIDI and SAIFI are required measures under the default price-quality path applying to Vector under Part 4 of the Commerce Act and have prescribed thresholds.

New Zealand practice requires that both of these measures consider only the impact of sustained interruptions related to high voltage (HV) distribution and sub-transmission network. Low voltage (LV) interruptions are excluded, on the basis that these are highly localised and generally affect only an individual or small cluster of customers. SAIDI and SAIFI include planned and unplanned events, but exclude Transpower or generator related events.

Vector Target

Disclosure Year	09/10	10/11	11/12	12/13	13/14	+5 yrs
SAIDI (Minutes)	104	114	114	114	114	114
SAIFI (Interruptions)	1.63	1.66	1.66	1.66	1.66	1.66

The step increases in SAIDI and SAIFI thresholds from 2010/2011 reflect the reset regulatory regime from 1 April 2010.Figure 4-7 shows the comparison of SAIDI for the current regulatory year to date against the regulatory target expressed as a straight line.

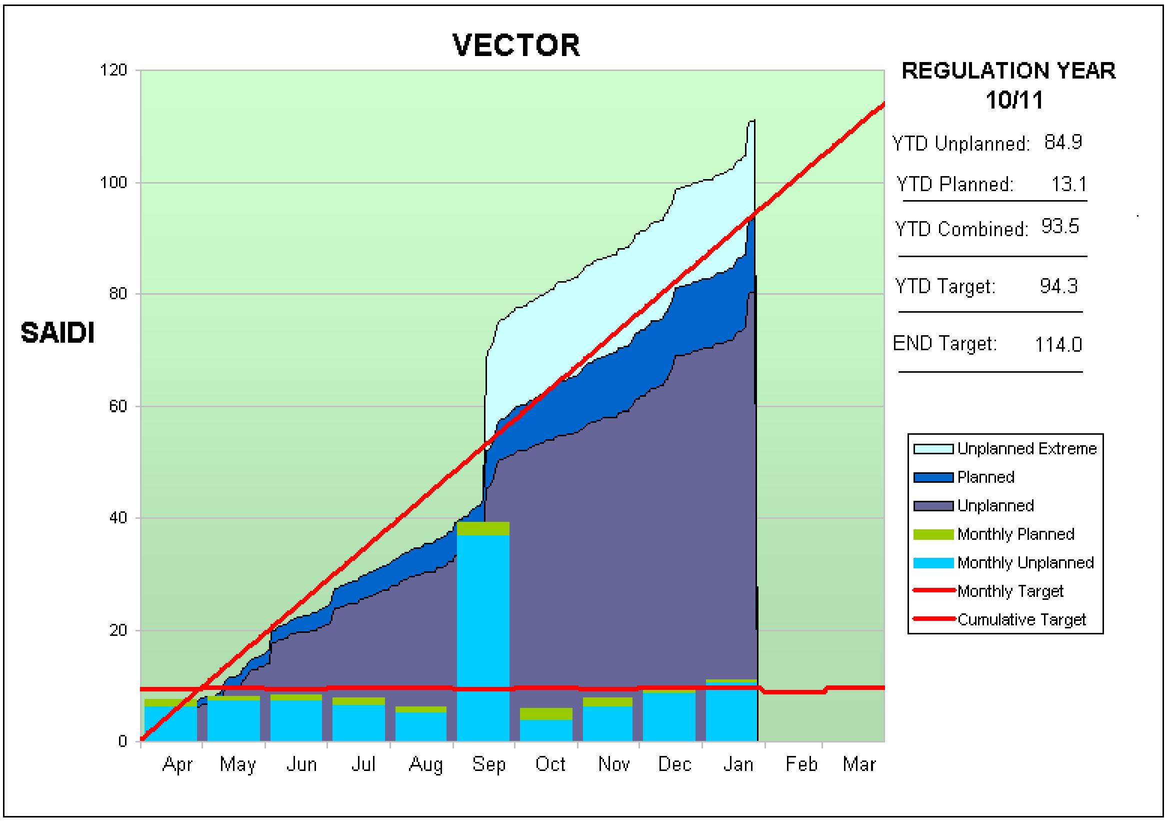


Figure 4-7 : Comparison of 2010/11 SAIDI against the regulatory target

The uppermost, light blue, area represents the impact of a storm spanning 17-18 September 2010. The storm meets the criteria stated in the Commerce Commission's 'beta methodology' to qualify as an extreme event, so is excluded from Vector's SAIDI score.

The dark blue area represents SAIDI resulting from planned shutdowns. Planned SAIDI has increased from last year due to a combination of higher workload and increased operational practices with certain types of equipment (which are the subject of a replacement programme).

The large purple area shows Vector's unplanned SAIDI. Note the step increase in September; despite relief for the storm's two peak days there was significant associated damage which did not meet exemption thresholds.

4.1.6.1 Trends in Supply Reliability

This section considers longer-term trends in Vector's supply reliability performance and provides a relative impression of how the network has historically performed.

The following Figure 4-8 shows Vector's SAIDI since the inception of information disclosure through to the last complete return. In order to illustrate Vector's underlying performance, "Excluded Events" have been identified, using the Commerce Commission's beta methodology, and "extreme threshold" SAIDI re-introduced.

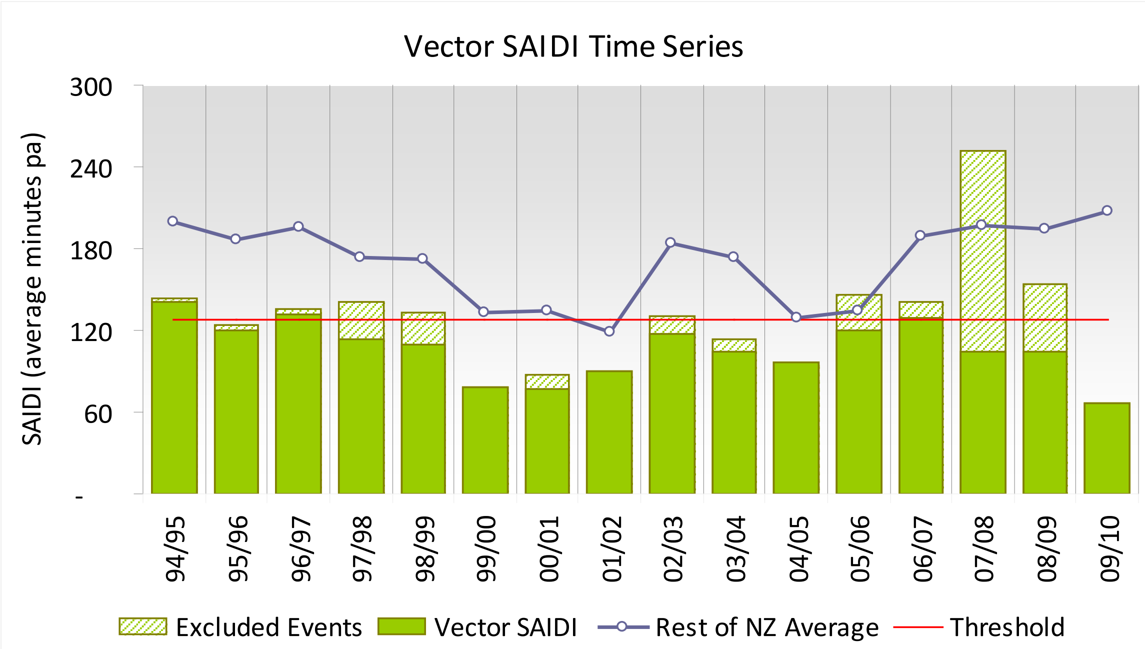


Figure 4-8 : Vector SAIDI time series

Vector's SAIDI compares well against other New Zealand Electricity Distribution Businesses (EDBs). Performance highs and lows are closely mirrored by the rest of New Zealand, indicating underlying country-wide factors, such as weather events.

The exceptional performance in 2009/10 can be attributed to a combination of settled weather, the inherent variability of SAIDI, enhanced vegetation control, and the benefits of judicious investment in automated protection devices in recent years, the impact of which may have been somewhat obscured in the last two to three years by events associated with poor weather.

Performance in the 2010/11 regulatory year has not been equally good. With over three months remaining the 2009/10 year-end SAIDI figure has already been exceeded. This does not represent a deterioration in underlying performance but rather, highlights the previous year's exceptionally good figure.

Figure 4-10 below shows each region's historical contribution to Vector's normalised SAIDI i.e. excluding extreme events.

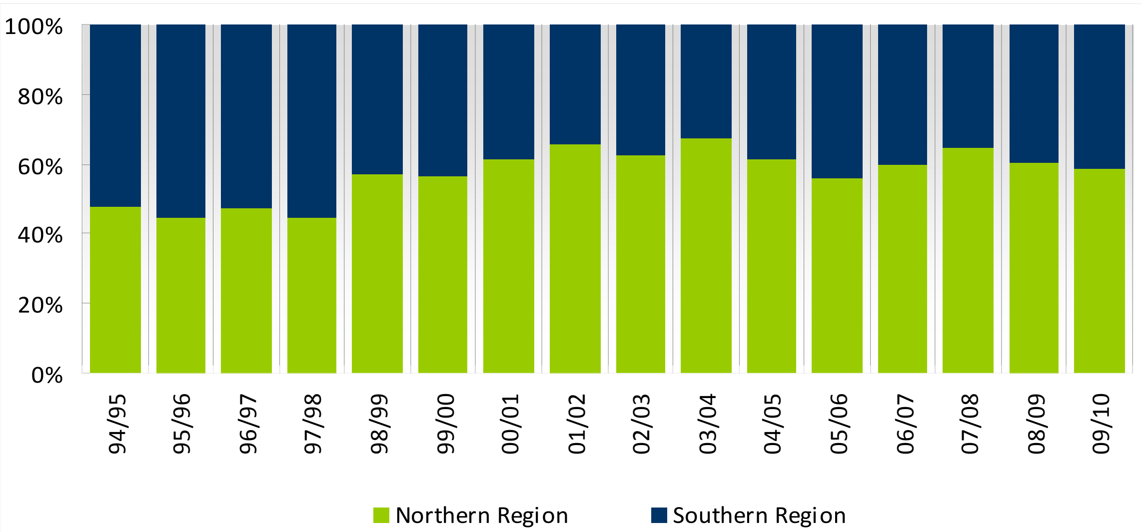


Figure 4-9 : Normalised SAIDI contribution by region

Vector's historic SAIFI performance is presented in Figure 4-10.

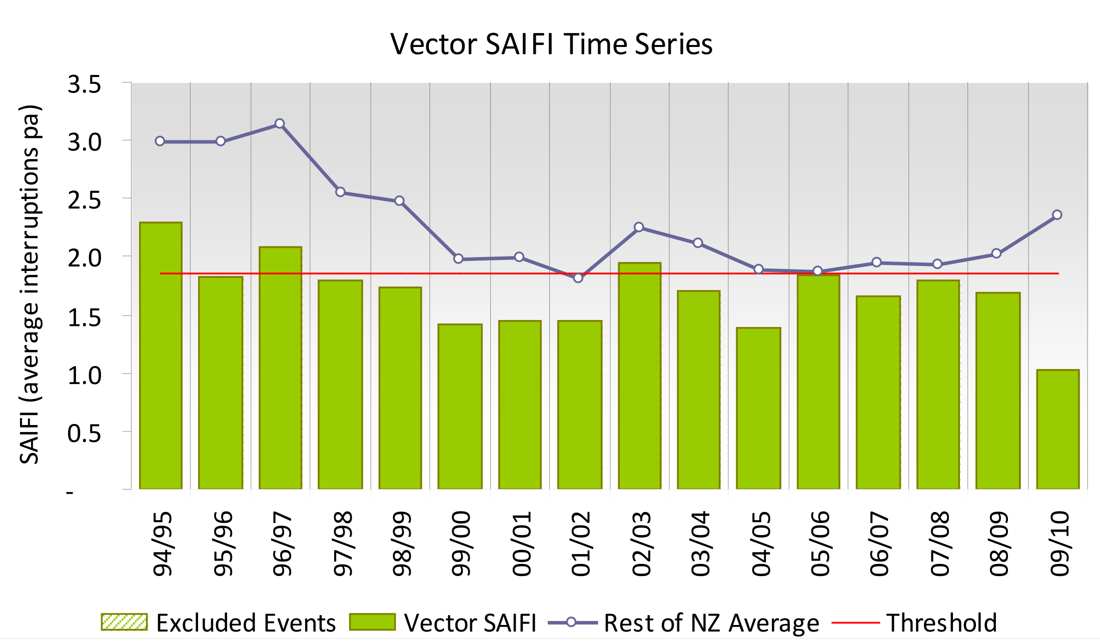


Figure 4-10 : Vector SAIFI time series

Note that the 2010/11 YTD SAIFI is tracking higher than last year's total. As with SAIDI, this represents a return to the norm compared to the exceptional 2009/10 result.

4.1.6.2 Causes of Interruptions to Supply

There are a number of reasons why interruptions to supply occur. Typically, on the Vector network, around 95% are unplanned and result from a range of causes including vegetation, animals, third parties, asset condition and adverse weather. Planned interruptions are generally undertaken for maintenance or network upgrade purposes.

Figure 4-11 shows how the impact of major causes of network interruptions has changed over the last 15 years. Each of these causes is considered in depth below.

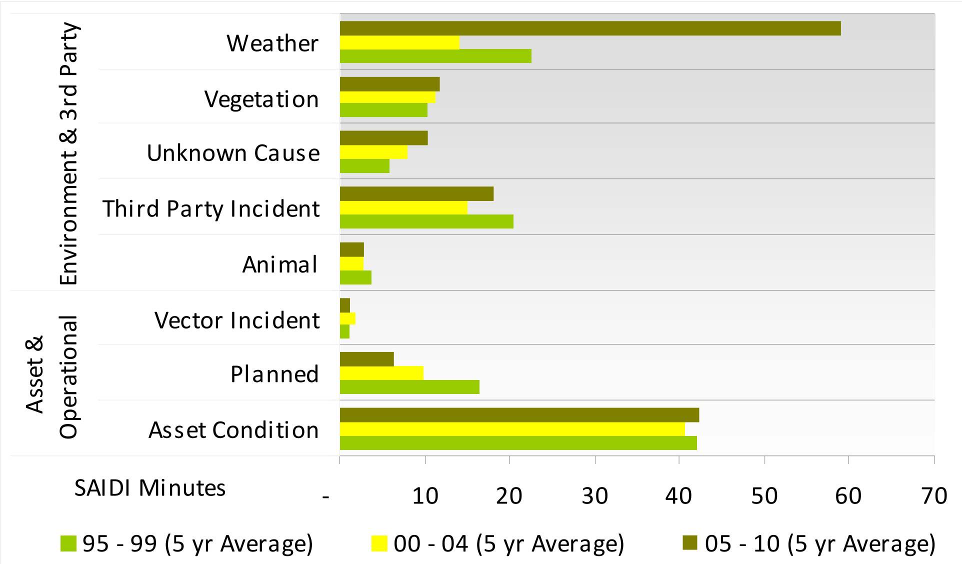


Figure 4-11 : Impact of major causes of network interruptions

- **Weather:** This includes events caused by lightning and wind. The weather represents the single most unpredictable and significant cause of interruptions to the Vector network, with a dramatic increase in events related to extreme weather over recent years (2009/10 being the exception).
- **Vegetation:** This includes faults resulting from overhanging branches and trees caught in power lines. Vector has dedicated a substantial amount of maintenance effort into its cyclic tree cutting and vegetation control programmes. The Electricity (Hazards from Trees) Regulations 2003 have clarified some of the uncertainty around clearance responsibilities and have forced much tighter management and increased education and public awareness. Vector is, however, concerned about some aspects of the regulations which we consider to be unworkable. Vector is actively participating in an industry working group to review the regulations.
- **Third party incidents:** These are caused by external interference, including cars colliding with power poles, vandalism, underground assets dug up by other authorities or trees cut down onto power lines by members of the public. Controls that continue to be put in place include additional network protection devices, increased public education, better coordination around locating and digging near underground assets and relocation or under-grounding of prone or repeatedly-affected assets.
- **Animals:** In most cases sustained interruptions are due to birds or possums. Possums climb along power lines whereas birds will often perch on overhead assets, creating a short circuit when bridging live parts. Many initiatives have contributed to a gradually reducing risk of animal failures, such as vegetation clearance, possum guards on new pole installations in wooded areas, replacement of air-break switches (ABSs) with fully enclosed gas insulated switches, replacement of pin insulators by post insulators with additional clearance.
- **Asset condition:** Although individually extremely reliable, the high quantity of assets installed across the network means that despite all practical efforts there will be some failures related to asset condition. In terms of contributing to the improvements in interruption time, assets with excessive failure rates are targeted for maintenance and renewal programmes, thermal and ultraviolet surveying continues to detect hot and potential breakdown spots, increased network protection devices limit the impact of interruptions and new non-invasive condition based detection techniques help direct risk based maintenance decisions. While underground assets are extremely reliable, being buried away from the weather and external influences such as trees or cars, overhead asset condition-related failures can be precipitated by weather and third party causes.
- **Planned interruptions:** The five-year average planned SAIDI has declined steadily, mainly due to live-line "glove and barrier" work practices and the increased use of back-up generation. Note that in the past two years this trend has reversed, partly due to the implementation of safety-driven operating restrictions on certain equipment types, which necessitated expanded isolation areas. Vector has a programme in place to accelerate the upgrade of the affected equipment over the next five years.

With the exclusion of last year’s exceptional result (where benign weather conditions resulted in unusually low environmental impacts), the trend has been for the proportion of SAIDI associated with environmental and third party incidents to increase over time; conversely the impact of asset and operational interruptions has reduced. This is illustrated in Figure 4-12.

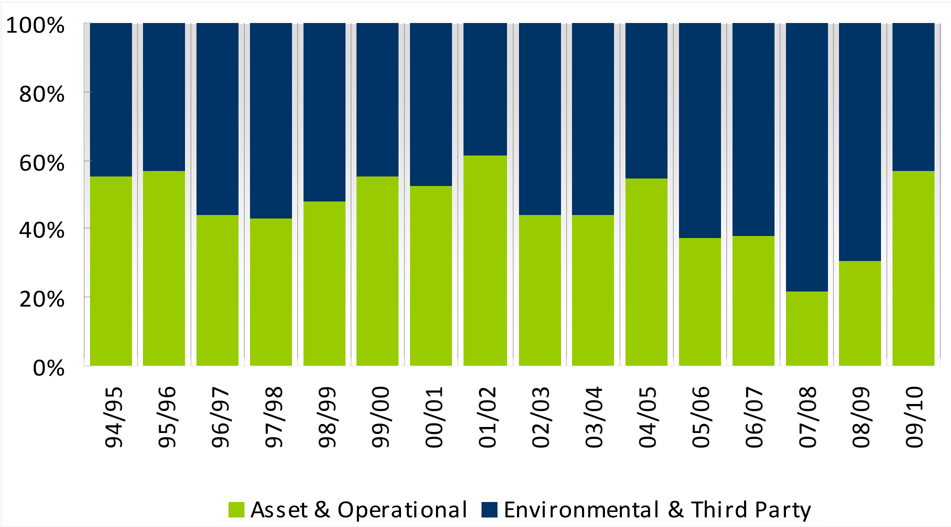


Figure 4-12 : Proportion of SAIDI associated with environmental and third party incidents

4.1.6.3 Factors outside Vector's control

Overall, around 40% of faults currently stem from environmental and external factors such as extreme weather, lightning, and third party interference (vehicular collisions with power poles, dig-ins, vandalism, un-escorted high load contacting overhead lines).

These are random events and largely beyond Vector's control. Certain operational and network design measures are taken to mitigate the risk. A sustained reduction in failure rate for these fault types would require significant scale penetration of any technical solution, which generally are well down the viability scale in terms of cost/benefit.

Note that while the settled weather of 2009/10 resulted in an increased proportion of asset and operational outages, this is a reflection of the reduced impact of environmental damage, rather than a higher number of other types of faults.

4.1.6.4 Mitigation of Interruptions to Supply

Measures to prevent faults and mitigate their impact include the application of appropriate and effective preventive and corrective maintenance strategies, together with proactive asset replacement programmes. Generally, reduced maintenance and asset replacement effort will, over time, result in increasing numbers of failures as the average age of the network increases, and the number of unresolved defects increases.

Approximately 60% of current faults are considered to be theoretically preventable. For example, equipment failure, human error and vegetation contact (other than in storms). The cost/benefit relationship of increased maintenance and asset replacement effort to reduce controllable fault frequency is, however, highly non-linear, with diminishing returns becoming apparent.

4.1.6.5 Reducing Restoration Time

Restoration and repair time is a function of many factors including time to locate the fault, network configuration, switching time, real-time information feeding into the control room, number, skill set and location of fault response field staff and availability of additional resource if the complexity of fault dictates.

Dependent on fault location and time of day, travel time can be a significant factor. For car versus pole incidents involving fatalities, the police now often restrict access to the site for several hours while they complete their crash investigation, which significantly delays the repair and restoration effort.

Vector works with its contracting partners to ensure there is a constant focus on improving fault response times by placing the right staff with the right skill sets in the right places and focussing the response on restoring as many customers as possible, as quickly as possible.

Fault finding time has been reduced through the use of carefully placed automation devices, fault indicators and the use of sophisticated protection relays.

Switching time for fault isolation and supply restoration could be reduced with additional switching staff or control room-administered distributed automation devices, or the deployment of intelligent field switching devices. Should a sufficient incentive exist in future to improve network reliability[2], this will be further pursued.

Finally, repair time is very much a function of fault complexity and available field resources. There is a trade off between a temporary repair with by-pass options such as local generation, or complete repair and restoration. Situations are assessed on a case-by-case basis to determine the most appropriate response.

4.1.6.6 Reducing the Number of Customers Affected by a Fault

To reduce the impact of a network failure, one solution is essentially to break up the network into smaller chunks i.e. with fewer customers between control devices.

This can be achieved by building additional zone substations between existing substations to shorten the feeders, adding additional feeders to reduce the number of customers per feeder or installing additional control devices into feeders to reduce the number of customers affected by any given failure. Automation of these control devices with local intelligence (so-called self-healing network) will also speed up restoration time.

The two most cost effective technologies currently available to achieve this are distribution automation and ground fault neutralisers. Network automation projects already implemented over the last three years at a cost of around $10 million are saving around 30 SAIDI minutes per annum on an on-going basis, as described below.

4.1.6.7 SAIDI Avoided by Automated Protection Devices

Over the past three years Vector has invested heavily in automated protection devices. Between 2006 and 2008, 202 automation devices were commissioned for a total expenditure of $7.85 million. Of the units installed:

- 70 sites operate as functional reclosers;
- 38 sites operate as functional sectionalisers; and
- 94 sites operate as intelligent control points, mostly interconnecting neighbouring feeders.

These units augment the 50 pre-existing reclosers on the network. All sites were selected on the basis of greatest SAIDI benefit per dollar cost.

[2] Current quality regulation does not support investments in improving network reliability.

Vector monitors the performance of these devices in terms of operations and SAIDI which would have been incurred if the device were not installed. The plot in Figure 4-13 is updated daily and available to all Vector staff on the company intranet.

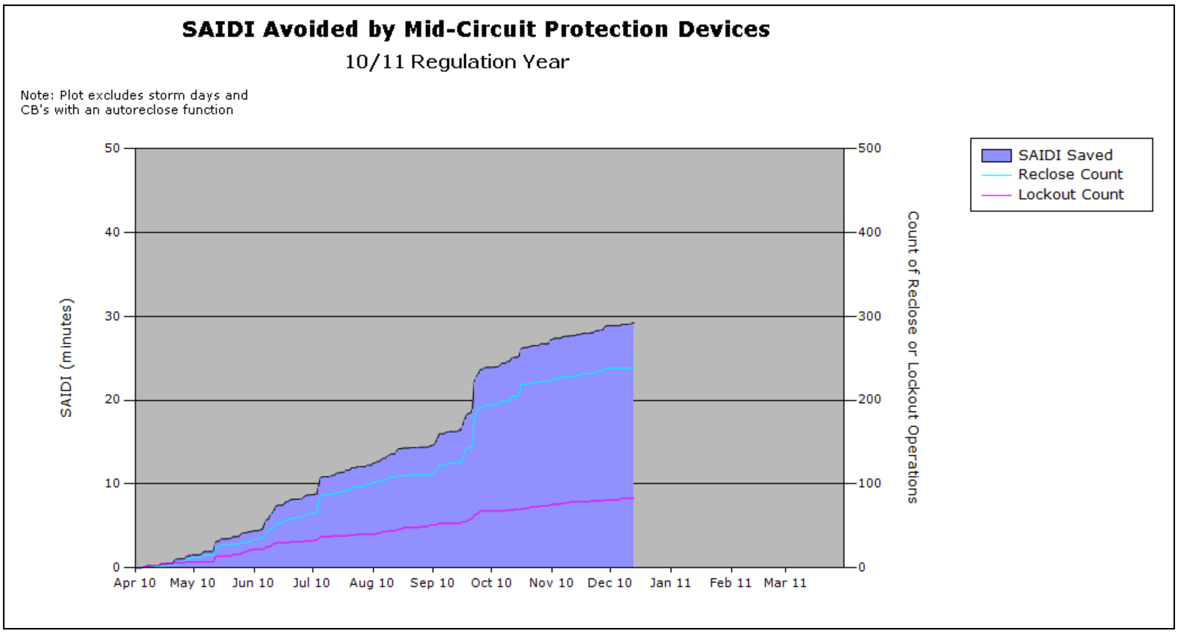


Figure 4-13 : SAIDI avoided by mid-circuit protection devices

Figure 4-14 shows the historical SAIDI benefits derived over the course of the programme.

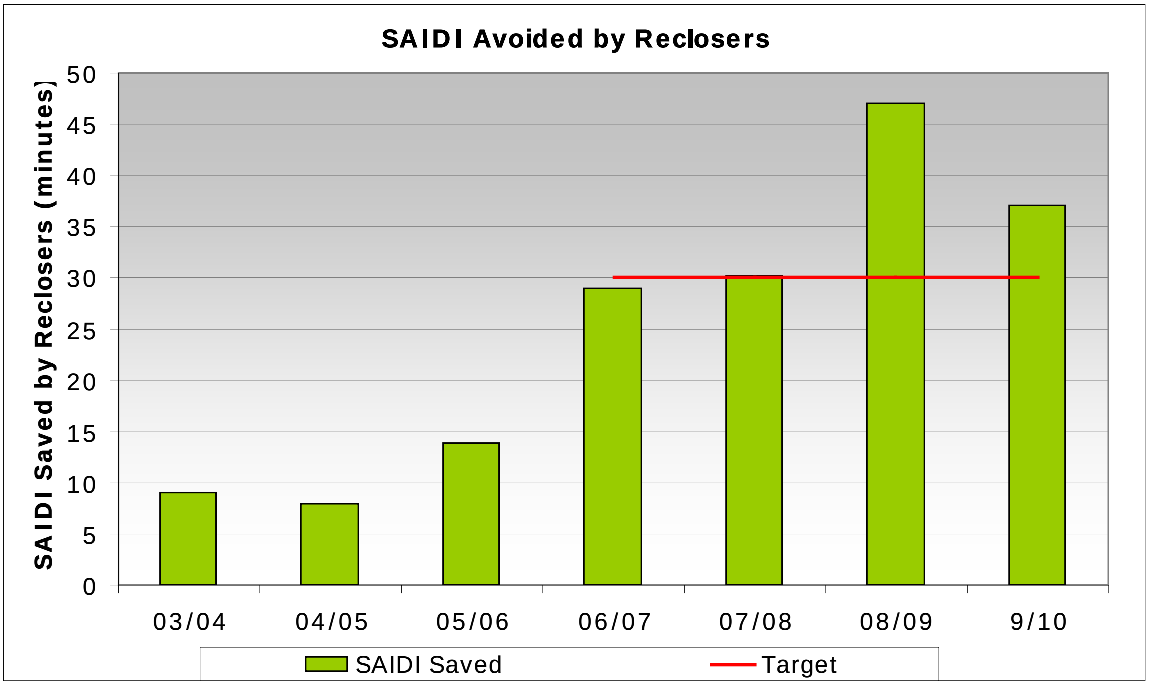


Figure 4-14 : SAIDI avoided by reclosers

4.1.7 Justification of Consumer Oriented Performance Targets

Supply reliability and response targets are normally established by taking into account customer needs on a qualitative basis, due to the complexity and informational requirements of quantifying customer requirements, and relating them to network performance.

As indicated by customer surveys, at present there is no evidence from the Vector customer base to support heightened (or reduced) levels of supply reliability, especially where these would involve increased line charges. In the absence of other drivers or incentives, Vector's quality targets therefore coincide with the regulatory quality targets, which are also based on historical performance levels.

4.1.7.1 Vector Promise and Charter Payments

If Vector fails to meet these service commitment targets, compensation schemes exist to acknowledge the inconvenience to the customer. As per the service targets, these compensation schemes are specific to the regional customer/retailer models.

The Southern region scheme is known as the "Vector Promise", under which a payment of $50 for residential customers and $200 for commercial customers (excluding large commercial customers) may be claimed by the customer on Vector's failure to achieve target.

The Northern region scheme is the "Charter Payment" system, under which Vector makes a payment of $40 for residential customers and $100 for commercial customers proactively to the retailer.

Vector takes this commitment seriously and compensation payments of almost $2 million have been paid in the last six years as shown in Figure 4-15 below.

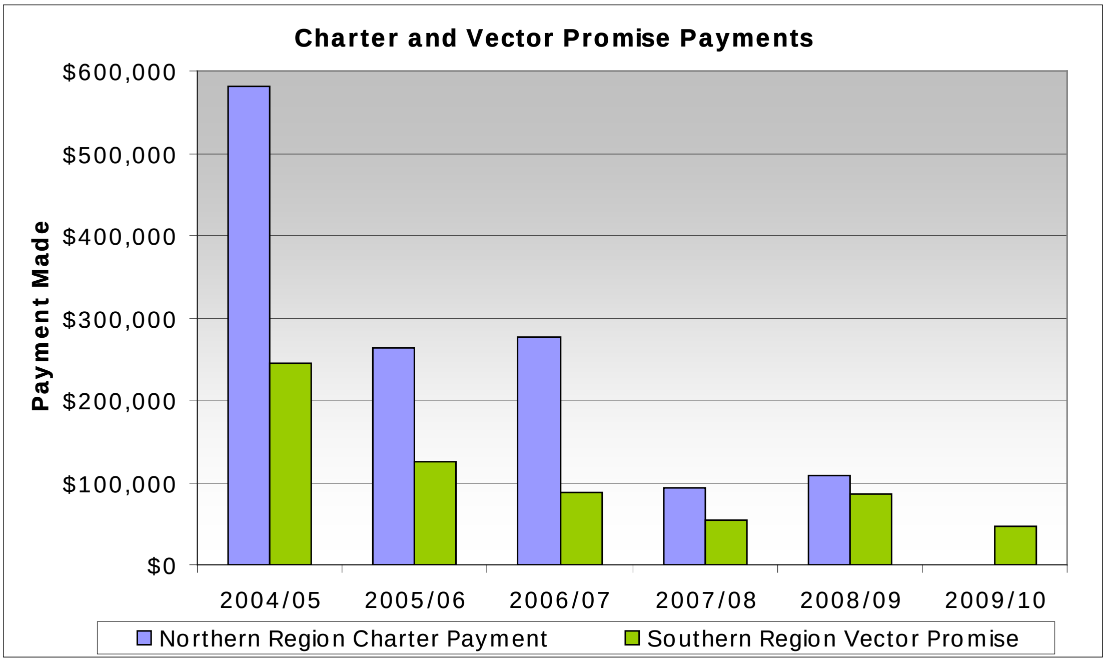


Figure 4-15 : Historic Service Commitment Compensation Payments

4.1.7.2 Enhancing our Performance for the Future

Supply reliability performance improvement programmes continue to address the following:

- Reducing the number of interruptions experienced by customers;
- Reducing the time customers are without electricity (including through expanding the use of remote monitoring and control to allow faster response and restoration times);
- Improving delivered supply quality (including introducing new technologies to reduce the impact of momentary voltage sags);
- Upgrading assets in the worst performing areas;
- Targeting major cause contributors to reduce the frequency of customer interruptions;
- Minimising the use of planned shutdowns by continuing to work live line where possible, and increase the use of generators to avoid outages; and
- Improvements in network and asset management information and related IT systems.

4.1.8 Process for recording network outage information

Operational responsibility of Vector's sub-transmission and distribution networks rests with the network control room. Resolution of planned and unplanned events is under direction of the duty control room engineer.

All planned and unplanned records are captured by the network control engineer both in hard copy (electricity fault switching log) and electronically (the HVEvents database). The HVEvents database records such fault details as outage type, system level, location, cause, customers without supply and restoration times. To ensure accuracy, each outage record is peer-reviewed by the network performance analyst. In addition, Vector's external auditors KPMG, reviews this process annually and conducts spot-checks for accuracy.

At year-end the period's average network customer base is calculated using the Gentrack billing and revenue system (averaging customers at the start and end of the year). The following reliability metrics are extracted from the HVEvents database for disclosure reporting:

- Interruption frequency by class;
- Interruption frequency by voltage level;
- Interruption duration by class; and
- SAIDI/SAIFI/CAIDI (calculated using average customer count).

The following figures (Figure 4-16 and Figure 4-17) show the process for recording outage information and the process for auditing the quality of the recorded data.

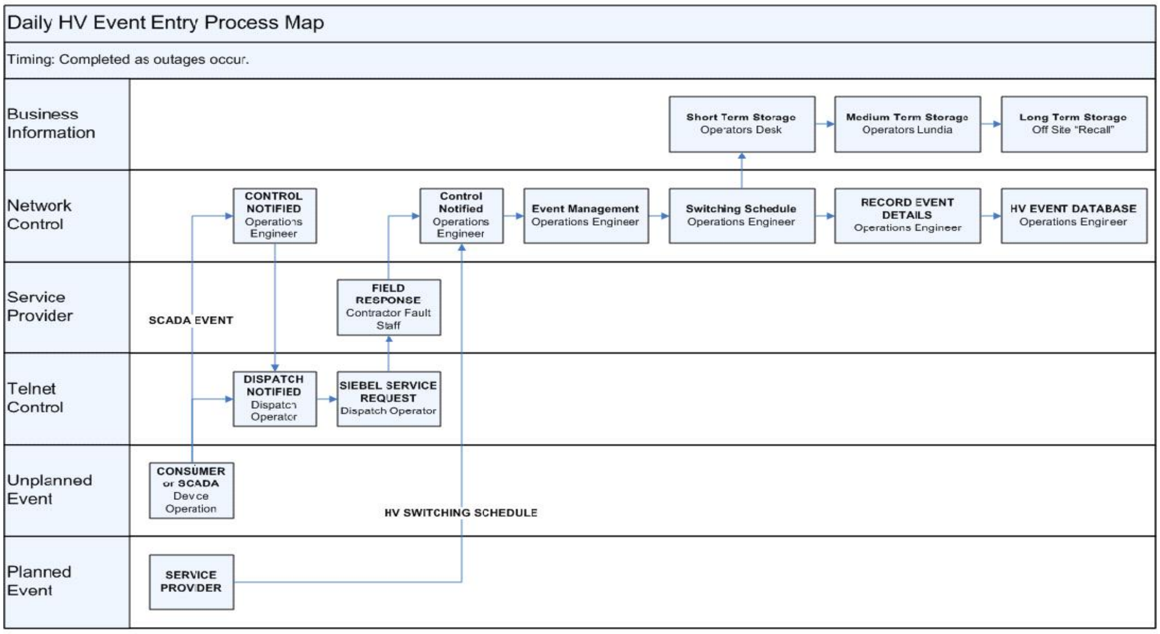


Figure 4-16 : Process for recording outage information

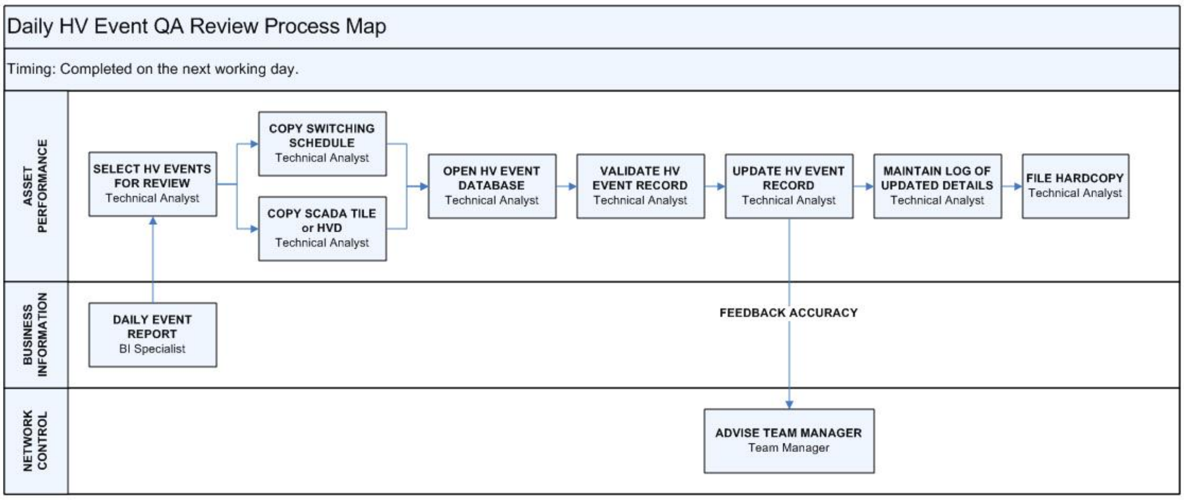


Figure 4-17 : The process for auditing the quality of the recorded data

4.2 Network Performance

4.2.1 Failure Rate

Asset failure (or fault) rate is a direct measure of the number of recordable events per system length, and provides a tool for understanding trends and anomalies in underlying network performance, and is defined as:

"The failure rate per 100 km of network length associated with MV distribution and sub-transmission faults."

The failure rate in 1997/98 was just over 12.5 faults per 100km, increasing to 18.5 faults per 100km for the 2008/09 year. To counter further increases various initiatives have been launched, including cable upgrades and a coordinated "Dig Safe" programme with other utilities and local authorities. It should be noted that the performance in the period 2005 to 2009 were significantly influenced by extreme weather events.

Last year's solid performance reflects a combination of the period's benign weather and Vector's initiatives taking effect.

Figure 4-18 below shows the Vector network equipment failure rate from 1994/95 through to 2009/10. The figures before the merger of UnitedNetworks and Vector (1994/95 to 2002/03) were the combined results of UnitedNetworks and Mercury Energy[3]/Vector.

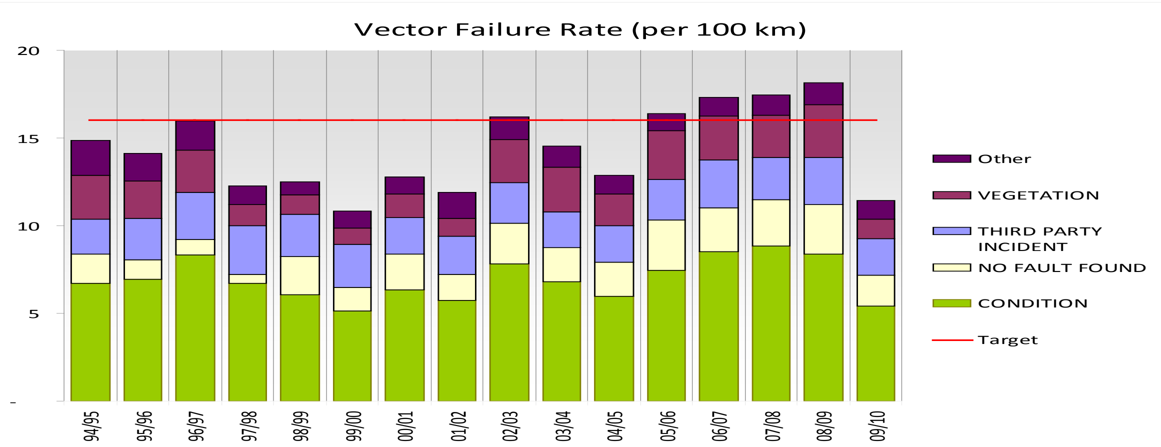


Figure 4-18 : Vector equipment failure rate

Vector has investigated its line failure rate, which appears to lie at the higher end of the New Zealand average. Beyond a few obvious contributing factors (such as weather), to date no compelling cause could be identified. The statistic appears counter-intuitive to Vector's overall reliability performance, which is significantly better than the New Zealand average.

Underlying this anomaly could be non-technical factors such as measurement and reporting accuracy, or the measurement methodology. Work continues to determine whether there are technical root causes for the fault rate and, should this prove to be

[3] Pre-sale of Vector's retail business and the brand name Mercury Energy.

the case, a strategy will be developed to address any underlying asset performance issues.

Vector's Network failure rate target is:

Vector Target

Disclosure Year	09/10	10/11	11/12	12/13	13/14	+ 5 Years
Failure Rate (per 100 km)	16	16	16	16	16	16

It should be noted that not all asset failures lead to supply interruptions. Asset failure rate provides a measurement of how the network performs. Reliability indices such as SAIDI and SAIFI, on the other hand, provide an indication of how often a customer loses supply and how long would it take to restore supply when an interruption occurs.

4.2.1.1 Causes of Network Failures

In general, the reasons for network failures are broadly similar to the reasons for interruptions to customers' supply, as illustrated in Figure 4-19.

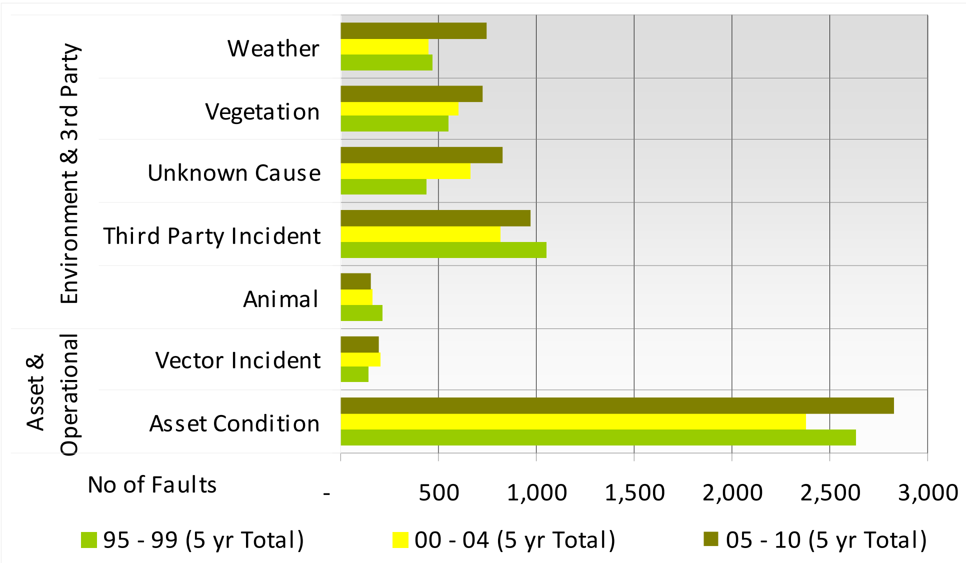


Figure 4-19 : Reasons for network failures

This shows the number of asset failures in each five year period, not the annualised failure rate normalised to the prevailing network length as per the definition.

Three specific causes of network failures are considered in more detail below:

- Faults due to Vector incidents - are the result of mistakes such as switching errors, accidental contact, dig-ins and accidental protection tripping, whether by Vector or Vector's FSPs or other contracting partners. Figure 4-20 below shows that these incidents remain relatively static at around 35 events per year, corresponding to a failure rate of 0.4/100km.

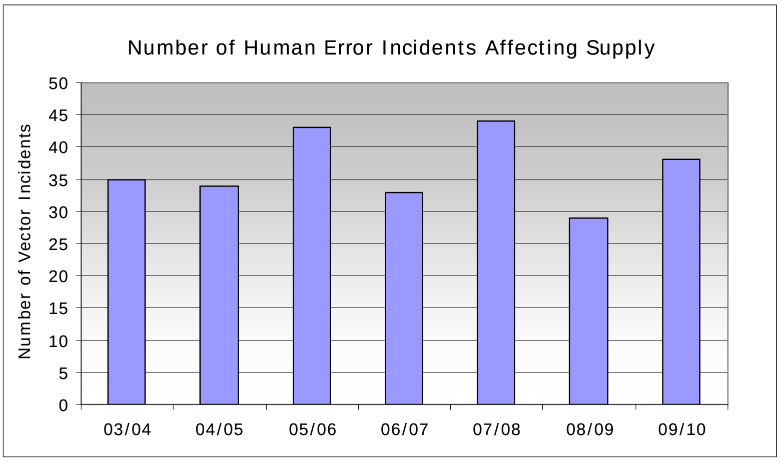


Figure 4-20 : Number of human error incidents affecting supply

This represents approximately 2% of the total failure rate (and a similar proportion of SAIDI and SAIFI). Nevertheless, as these events are within Vector's control, all such incidents are investigated thoroughly, especially those with health and safety, or environmental implications. Permanent corrective actions are implemented where applicable;

- Reported Protection Malfunctions - Vector tracks failures where protection either fails or operates in a manner inconsistent with the Control Room Engineer's expectation. In most instances, the apparent protection failure is not the cause of the outage but is a complicating factor. Figure 4-21 shows annual protection malfunction counts and their proportion of total faults.

  Each instance where protection is thought to have malfunctioned is flagged to Vector's Protection and Control team for investigation. Corrective actions (including operator training) are implemented to avoid repeat incidents, where applicable.

  Historically, the rate of protection malfunctions was considered high. This was partly as a result of the complex, meshed nature of the Northern network and the associated need for sophisticated protection schemes. To address this, Vector embarked on a systematic programme to upgrade the protection schemes for the Northern network to computer-based systems, conforming to best industry practice. The impact of this is starting to show in the improving trend shown in Figure 4-21 below.

- Failure rates by type of equipment are being developed and will be progressively introduced now that the TAM register project has been is implemented and exhaustive fault data is being collected (refer to Section 7). This will also allow the monitoring and analysis of defect rates; and

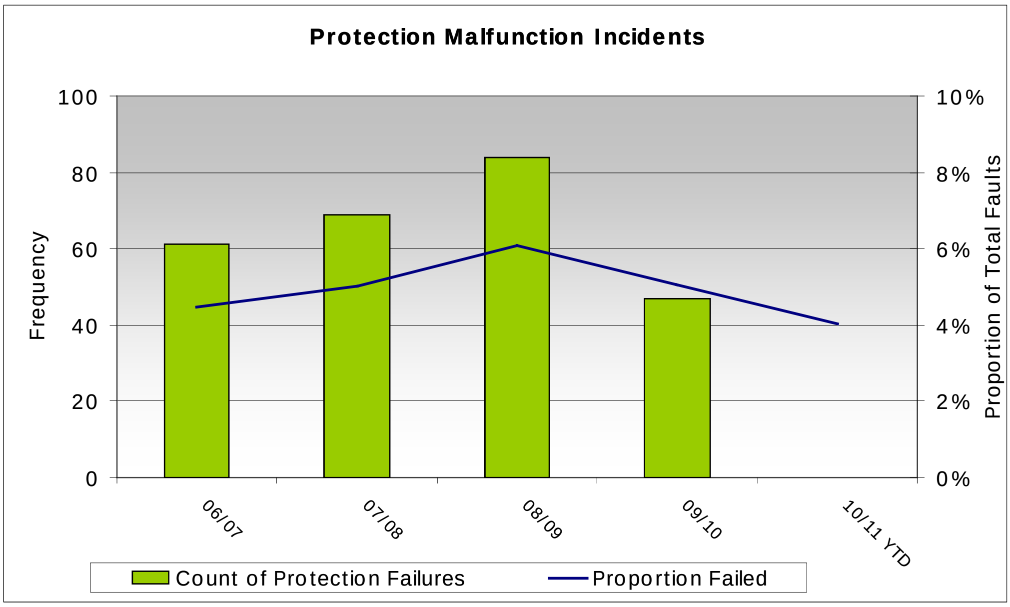


Figure 4-21 : Protection malfunction incidents

- Failures due to unknown causes (see Figure 4-22) - these occur when circuit protection devices operate to initiate interruption to customers but, after fault finding and line patrol, no cause can be isolated or observed and the circuit is re-energised. The interruption cause is recorded as unknown although there may be a suspected cause, such as vegetation brushing overhead lines or conductors clashing in stormy weather.

  The 2009/10 regulation year shows a decline in both the count of unknown faults and their proportion of total faults. This decrease is a result of the benign weather conditions (stormy conditions result in higher numbers of unknown faults) and does not necessarily demonstrate a declining trend.

  Vector aims to maintain unknown faults at less than 10% of the total fault frequency.

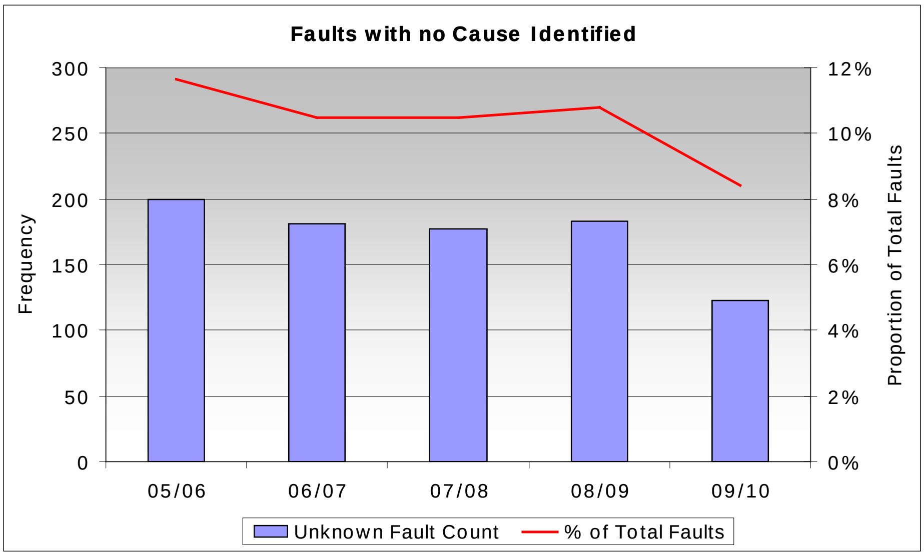


Figure 4-22 : Faults with no cause identified

4.2.1.2 Reporting and analysis of network faults

Vector records interruptions to its HV and medium voltage (MV) network in a fault reporting system, HVEvents (described in detail in Section 7). This system enables analysis of trends and anomalies in the performance of the network down to the distribution transformer level. In Figure 4-23 to Figure 4-25 examples of extracts from HVEvents are illustrated.

In this way, supply reliability performance improvement programmes can be prioritised to address the more significant issues, focussing on those that are theoretically preventable, as described above.

From beginning of February 2010 To end of February 2010

Region Northern

1 of 2 100% Find | Next Select a format Export

Vector Unplanned Outage Report

From 1/02/2010 To 28/02/2010

Region: Northern

KEY:	Cust Affec	Vector SAIDI	Max Time Off (mins)
	0	0	0
	1-200	0-0.1	0-120
	201-500	0.1-0.2	120-150
	201-1000	0.2-0.5	150-180
	1001+	>0.5	180+

Click on the blue hyperlinks to go into further detail regarding an individual outage.

Event ID	Date	Time	ZBC	System Level	Location	Substation	Main Reason	Sub Reason	Event Cust Affec	Vector SAIDI	Event Max Time Off
197969	28/02/10	20:27	Electrix	Feeder	07MAHO	Coatesville	THIRD PARTY INCIDENT	OTHER	1,598	0.104	37
197965	28/02/10	04:01	Electrix	Feeder	31RANU	Swanson	NO FAULT FOUND	PATROLLED	1,259	0.137	57
197953	25/02/10	13:00	Electrix	Feeder	11LAKE	Hauraki	EQUIPMENT - OH	CROSSARM	223	0.018	42
197951	25/02/10	09:06	Electrix	Zonesub	04BIRKDA		THIRD PARTY INCIDENT	DIG-IN	8,675	0.351	131
197950	24/02/10	23:04	Electrix	Subtrans	(52A) 647		EQUIPMENT - OH	INSULATOR	0	0.000	0
197946	24/02/10	06:26	Electrix	Feeder	38MATA	Warkworth	NO FAULT FOUND	PATROLLED	81	0.011	71
197940	23/02/10	03:05	Electrix	Feeder	09GLED	James Street	ANIMAL	OTHER	119	0.042	187
197939	22/02/10	15:35	Electrix	Feeder	13WAIT	Helensville	EQUIPMENT - OH	OTHER	3	0.001	205
197935	21/02/10	22:15	Electrix	Feeder	30JUNI	Sunset Rd	EQUIPMENT - UG	CABLE	69	0.018	135
197931	20/02/10	13:20	Electrix	Feeder	07SCRE	Coatesville	THIRD PARTY INCIDENT	OVERHEAD CONTACT	708	0.070	116
197929	20/02/10	02:20	Electrix	Feeder	27HUAP	Riverhead	NO FAULT FOUND	PATROLLED	11	0.005	240

Figure 4-23 : Example report from HVEvents showing unplanned events in the Northern region during February 2010

Year 2010 Month March
Day Sunday 7

1 of 1 100% Find | Next Select a format Export

HV Event Report

Events that have on 07 Mar 2010

KEY:	Cust Affec	Vector SAIDI	Max Time Off (mins)	Recent Trend vs SLA
	0	0	0	
	1-200	0-0.1	0-120	OK
	201-500	0.1-0.5	120-150	< SLA
	201-1000	0.5-1	150-180	= SLA
	1001+	>1.0	180+	> SLA

Click on the blue hyperlinks to go into further detail regarding an individual outage.

Unplanned Events

Event ID	Date & Time	Region	System Level	Location	Substation	Main Reason	Sub Reason	Cust Affec	Vector SAIDI	Max Time Off	Faults Last 12mths	FAIFI*
198011	7 Mar 19:30	Northern	Feeder	28AWAR	Sabulite Rd	THIRD PARTY INCIDENT	VEHICLE DAMAGE	324	0.128	208	2	1.2

Planned Events

Event ID	Date & Time	Region	System Level	Location	Substation	Cust Affec	Vector SAIDI	Max Time Off (mins)
198009	7 Mar 08:31	Northern	Feeder	26CENT	Orewa	56	0.005	47
198010	7 Mar 08:04	Auckland	Feeder	HOBS 32	Hobson	2	0.000	21
198008	7 Mar 07:06	Northern	Feeder	37RATA	New Lynn	37	0.006	90

Auto Reclosers Events

Event ID	Date & Time	Region	Location	Substation	Reclose Events last 1mth
198007	7 Mar 00:29	Auckland	OTAR 16	Otara	1

Figure 4-24 : Example of daily fault report from HVEvents reporting system

UNPLANNED HV EVENT DETAILS	
Event ID	198011
Date	07/03/2010 19:30 p.m.
Region	Northern
System Level	Feeder
Substation	Sabulite Rd
Location Code	28AWAR
Location Name	AWAROA RD
Main Reason	THIRD PARTY INCIDENT
Sub Reason	VEHICLE DAMAGE
Operational Details	
ZBC	Electrix
Contractor	Electrix
Operations Engineer	Vernon Molloy
Field Person	Ganesh Ram
Comments	Car v pole in Awaroa Rd, Sunnyvale. Emergency shutdown carried out to replace Pole.
Service Request Nr	1-184817033
Defect Number	
Location Details	
Street Address	78 AWAROA ROAD
Suburb	SUNNYVALE
Closest Asset 1	Pole #74496
Closest Asset 2	
Fault Trip Details	
Fault Trips	0
Trip Device	
Device Nr	
Protection Operation	OK
Function	
Protection Comments	
FPI Operation	Not Specified
FPI Comments	

Figure 4-25 : Example of detailed information captured for an individual event in HVEvents

4.2.1.3 Enhancing our Performance for the Future

Initiatives directed at reducing network failures include the following:

- Making improvements in Vector's management of asset lifecycle information (as described in Section 7);
- Development of network monitoring and control, and related IT systems;
- Upgrading assets in the worst performing areas;
- Evaluating technological developments in network monitoring, protection and control systems and in primary and secondary plant and equipment; and
- Targeting major cause contributors to reduce the frequency network of failures.

4.2.2 Asset Utilisation

Asset utilisation in a distribution network is defined as the ratio between the peak demand conveyed by an asset (such as a feeder or a zone substation) and the capacity of the asset. It is a measure of what an asset is actually delivering against what it is capable of delivering. At Vector, utilisation of an asset is measured as the single highest peak demand (after removing any temporary loading due to operational activities) divided by its installed capacity. In the case of substation utilisation, the maximum continuous ratings (MCR) of transformers installed are used. In the case of feeders, the cyclic ratings of the cables or overhead lines are used. The following graphs (Figure 4-26, Figure 4-27, Figure 4-28 and Figure 4-29) show the utilisation of zone substation and feeder in the Southern and Northern regions.

These graphs aim at showing the utilisation of the whole zone substation and feeder population across the two regions to give a view of the utilisation profile of the two regional networks. The utilisation profiles for the past three years (2008, 2009 and 2010) are plotted. We have chosen to monitor asset utilisation using a profile approach instead of a single average or median figure as this gives a more holistic picture of the network.

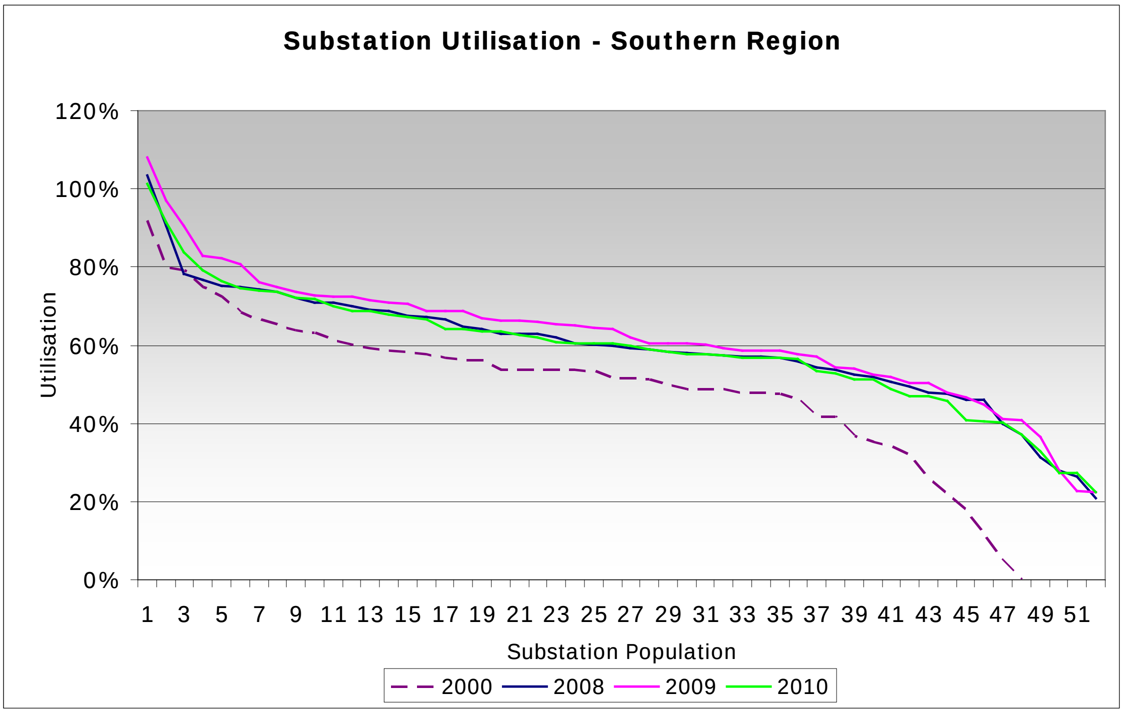


Figure 4-26 : Substation utilisation - Southern region

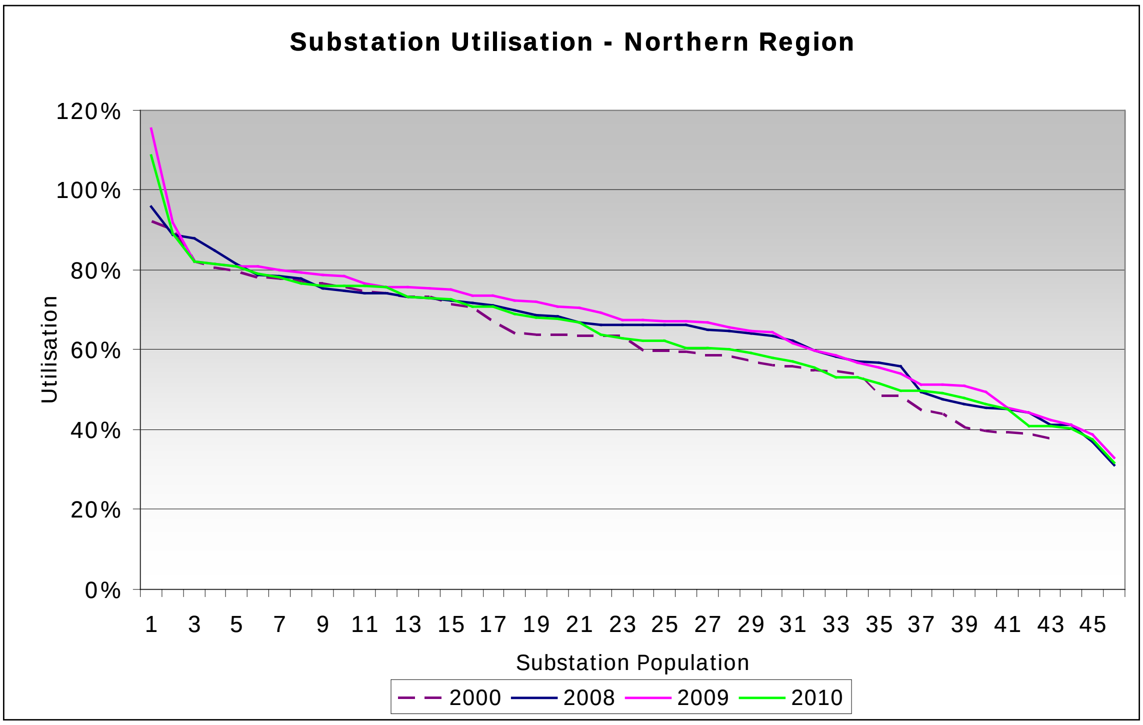


Figure 4-27 : Substation utilisation - Northern region

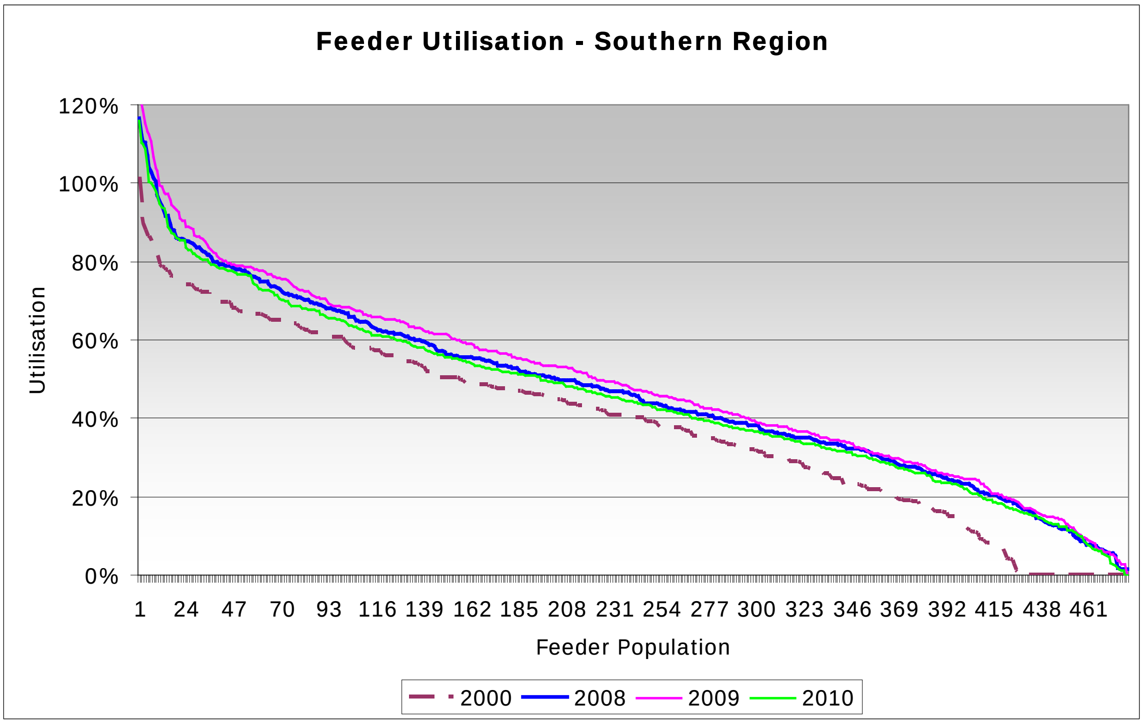


Figure 4-28 : Feeder utilisation - Southern region

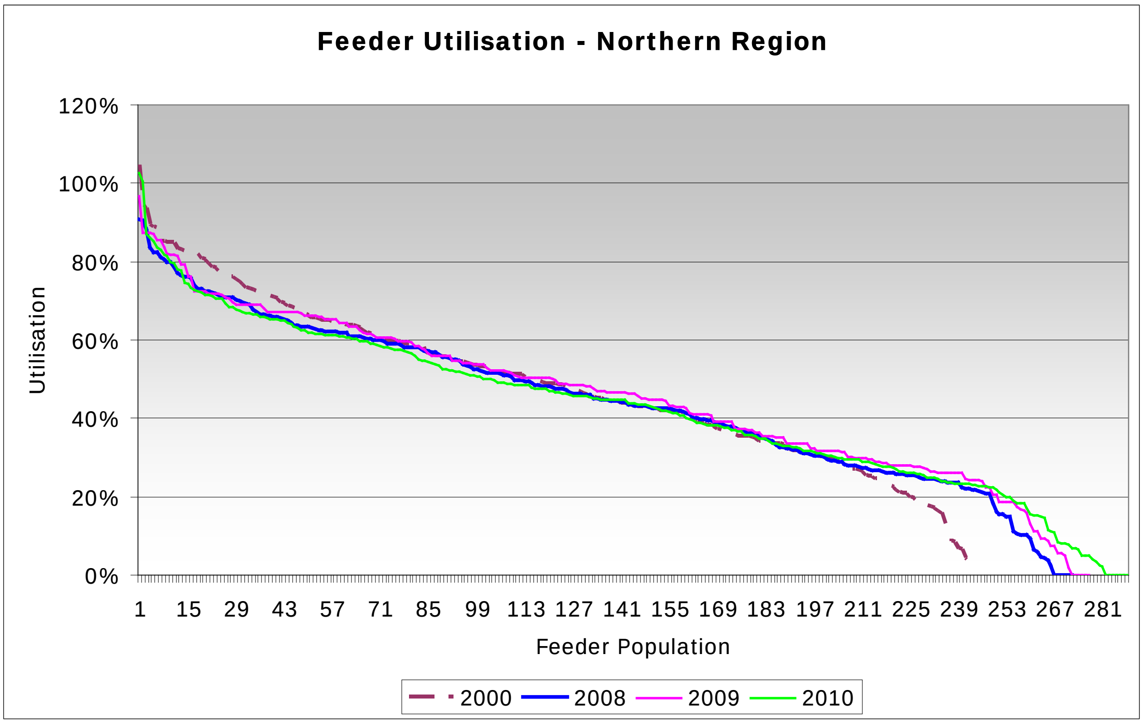


Figure 4-29 : Feeder utilisation - Northern region

The graphs demonstrate that within a network the utilisation of the assets are not uniform. Some substations (and feeders) are better utilised than others. While the ideal situation would be to have the utilisation profile as a flat horizontal line close to the limit of acceptable risk, in practice, geographical and physical constraints and economic factors often preclude network planners from achieving such a goal. The utilisation profile, however, provides the planner an indication of areas where assets are under or over-utilised (a security risk), so appropriate actions (such as load transfer, demand side management, and network reinforcements) can be taken.

The year-on-year utilisation profiles may move up or down due to the effect of weather on peak demands, but as a trend the utilisation of feeders and substations has increased over the years observed. For example, the median utilisation of substations in the Southern region has increased from 54% in 2000 to 60% in 2010. This represents a six percentage point increase (or an 11% increase in utilisation over the past eight years). At the top end (high utilisation), the increase is much less significant indicating that off loading of heavily loaded substations is taking place. As the substation capacity used in utilisation calculation is the MCR, utilisation above 100% is acceptable subject to the cyclical nature of the load.

Note that at the lower end of the graph, the results are not entirely reliable due to loss of data in the Plant Information (PI) system collecting and storing the load information. This is currently being addressed by upgrading PI to provide instant notification of missing or non-valid data.

The graphs also show marked difference in utilisation between the two regions. This is largely as a result of legacy issues – the architecture of the networks largely determines the utilisation.

For example, the Northern region has a significantly higher substation utilisation than the Southern region. This reflects the historical differences in sub-transmission design philosophy of the two regions before the Vector/UnitedNetworks merger and the manner in which supply quality and risk is managed.

The apparent higher risk to the Northern region sub-transmission system, as reflected through higher utilisation, is compensated for by the extensive interconnection at distribution level, which is not available on the Southern network. (This is not something that can be identified by utilisation graphs alone.) Caution must therefore be exercised in making simple judgements based on utilisation figures. More than a single measure is required to form a holistic view on the performance of a complex business such as an electricity distribution network.

While Vector is broadly striving to improve utilisation levels, currently no fixed target for utilisation has been set. A fixed target is not realistic given the significant difference in geographical and network topological characteristics, consumption patterns and customer categories served. Instead Vector has chosen to regularly monitor asset utilisation and use the information to focus on assessment of the risks faced by certain parts of the network.

4.2.3 Network Security

"Security" is defined as the ability to supply network load following a fault (or more than one fault) and can be categorised deterministically or probabilistically.

Deterministic security operates in discrete levels, typically defined as having sufficient capacity to supply customers following a single fault ("N-1") or two faults ("N-2").

Probabilistic security takes into account load curves and the likelihood of faults as well, allowing for intermediate security levels between the discrete levels set by deterministic practices.

For Vector's network a combination of deterministic and probabilistic criteria are used. This is described in detail in Section 5.3.

The term "capacity" is used to define the rating of assets caused by physical limitations of the equipment and is generally determined by heating effects.

Three most common ratings are:

- Maximum Continuous Rating (MCR): Equivalent to a constant load applied continuously to the circuit;
- Cyclic rating: Maximum load that can be applied based on the daily cyclic load profile; and
- Emergency rating: Short-term rating (generally two hours) which allows assets to be overloaded for a short period (followed by a cooling period).

Both security and capacity, as means of characterising the network, are very distinct measures from reliability, which is a measure of the ability of the network to supply consumers' requirements as and when required (usually measured in terms of SAIDI/SAIFI), as described in Section 4.1.

As illustrated in Figure 4-30, under normal conditions maximum demand can be delivered. After a network fault has occurred, demand can generally still be met. However, if the fault occurs during peak load times, there may be some interruption, governed by the following design standards:

- Commercial - up to 2% of the time; and
- Residential - up to 5% of the time.

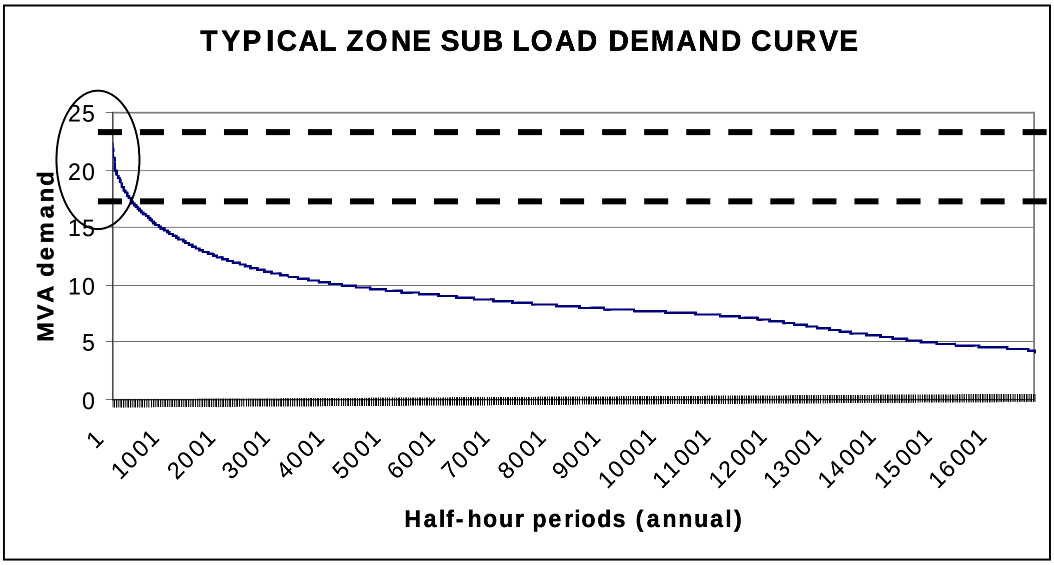


Figure 4-30 : Typical zone sub load demand curve

The upper line indicates normal capacity; the lower line indicates capacity after a single contingency (sub-transmission fault).

Vector's capacity standard is to maintain sufficient network capacity to supply all consumers' normal requirements under normal network conditions. In some cases short-term component overloading is accepted, as shown in Figure 4-31 below.

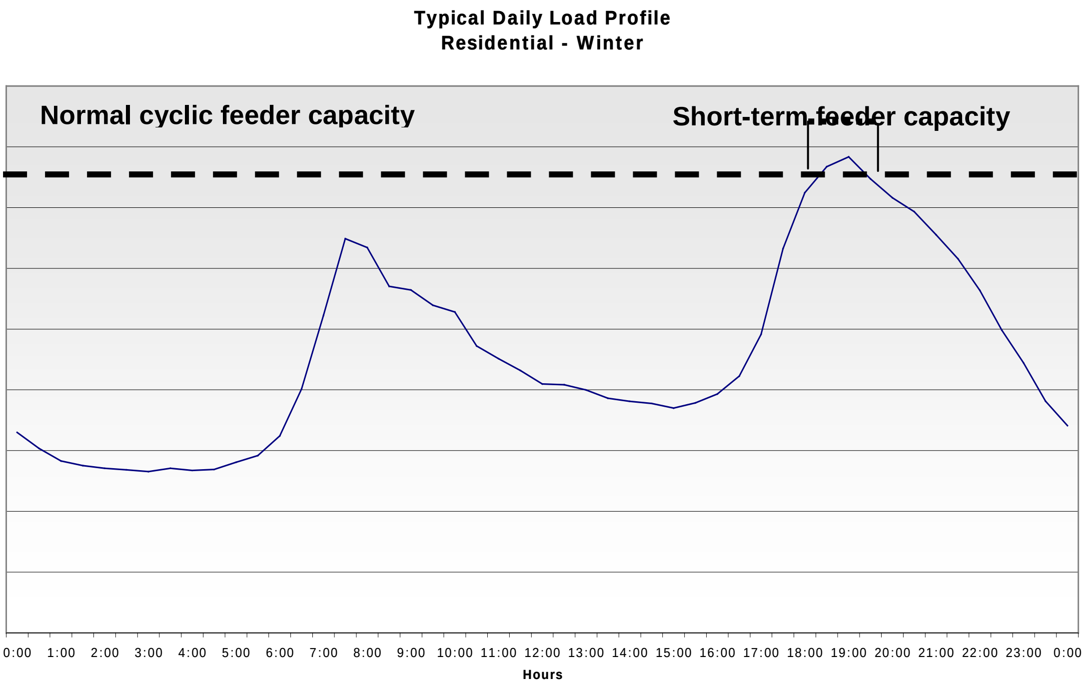


Figure 4-31 : Typical residential (winter) daily load profile

This daily load profile curve illustrates short-term feeder capacity above normal cyclic feeder capacity.

The plot in Figure 4-32 below shows the historic number of zone substations operating outside Vector's security criteria during peak demand times.

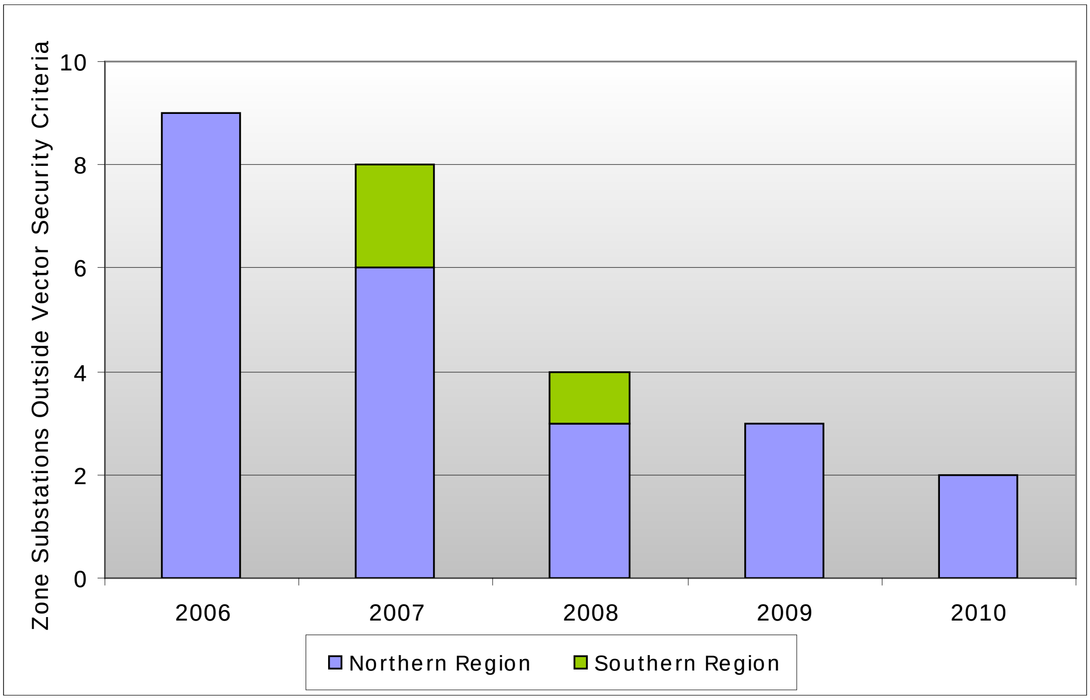


Figure 4-32 : Number of zone substations outside Vector security criteria

The downwards trend demonstrates the effectiveness of Vector's asset investment programme, which over the last 12 months has included three new zone substations and numerous HV feeders. Vector intends to fully address the zone substation security breaches during 2011.

4.3 Works Performance Measures

4.3.1 Capital Efficiency

Vector has embarked on a major capital efficiency drive – this is one of the Asset Investment (AI) group's key short and medium-term business goals. Metrics are being established to track progress.

- **Growth Capex Efficiency**

  This metric is designed to track the efficiency of investments made to support growth on the network. The metric needs to take account of investments which are implemented to reduce demand, new technologies (such as distributed generation), as well as smart thinking applied to more traditional solutions.

  The metric will relate to the ratio of annual increase in "effective capacity" to annual capex investment.

  The effective capacity measure will include both actual network capacity and demand side capacity managed e.g. through load control.

- **Asset Integrity Capex Efficiency**

  Replacement of assets due to condition presents a more complex metric, due to the diversity of efficiency measures that may be applied e.g. assets with longer life, lower cost of projects, refurbishment rather than replacement etc.

  The metric will relate to the ratio of annual increase in "asset life value" to annual capex investment.

The asset life value will be calculated from consideration of asset replacement cost and asset remaining life.

- **Performance Monitors**

  It is important to ensure the drive for capital efficiency does not result in undesirable outcomes. For this reason, the above metrics will be considered in combination with metrics such as SAIFI and asset utilisation percentage.

4.3.2 Capital Works Delivery

Capital work is scheduled physically and financially from the time a project is in proposal stage. Each project is split into a number of stage gates that state delivery expectations from defining the solution, through to final commissioning and close out. These stage gates are monitored monthly and reported to General Manager level. Project Initiators, Engineers and Contract Managers meet on a monthly basis to discuss project progress and issues and roadblocks are quickly escalated.

Once a project is past the solution defining stages and into delivery, the physical and financial forecasts are reviewed and re-set if appropriate. From this time, each part of the project is reviewed in terms of actual delivery against forecast.

To ensure focus remains on delivery of the works programme, our FSPs have profit at risk KPIs associated with delivery against forecast.

Monthly forecasts are compiled for the whole programme of work and circulated to executive level. Actual against forecast is also tracked as part of the executive dashboard metrics.

Each month an exceptions report is submitted to the board, which details the number of active projects with a value greater than $500,000 and their status. This report is designed to provide a no surprises environment, where projects with time or budget issues are highlighted at an early stage.

4.3.3 Field Operations Performance Assessment

A performance incentive scheme has been agreed with Vector's FSPs that is intended to:

- Measure the performance of Vector and the FSPs through the establishment of KPIs and provide appropriate incentives to deliver the required performance by both parties;
- Recognise that the FSPs entitlement to any incentive payment is dependent upon its performance as measured against KPIs, and drive continuous improvement and efficiencies through the annual review of the KPIs and the criteria for those KPIs; and
- Recognise that Vector's performance within key processes is critical to the FSPs' ability to deliver overall results.

Systems have been developed and implemented to provide visibility to both Vector and FSPs on their respective performances against KPIs that employ end-to-end measures.

For each KPI, there is a "meet" and "outstanding" performance incentive level; in some cases there is an additional "not meet" disincentive criterion. KPIs have been established for Vector's FSPs in the following areas, which are described in more detail below:

- Network performance;
- Delivery and quality of works;

- Health, safety, environmental and people;
- Cost management and efficiency; and
- Information quality.

4.3.3.1 Network Performance

The network performance KPI comprises Vector's regulatory SAIDI target (excluding any extreme events that are excluded by the Commerce Commission), and a target around response time to network faults as measured against the various customer service levels.

The targets for onsite response to electricity distribution faults in each customer category are shown in Table 4-5 below.

Customer Category	Target for Onsite Response (minutes)	
	HV Faults	LV Faults
Commercial customers	60	70
Urban residential customers	70	80
Rural customers	80	90

Table 4-5 : Electricity distribution fault targets

4.3.3.2 Delivery and Quality of Works

The KPI for delivery and quality of works provides for assessment of:

- Completion of all reactive, corrective and planned maintenance works to the agreed plans within the agreed timeframes;
- Customer connections from customer initiation within the target periods defined below or to the schedule agreed with the customer;
- Completing Vector initiated network projects within the agreed schedule; and
- Completion of works compliant to industry construction standards, Vector's network standards, national and local codes of practice, resource consents and other conditions without the need for corrective rework.

Vector Target

Customer connections targets:

- For LV connections, provide the quotation back to the customer within five business days of the application being made and complete the installation within ten business days of the customer accepting the quote and all road access approvals, or on date agreed with the customer.
- For larger customer connections, provide proposals to Vector within ten business days once the works scope is agreed with the customer. Vector to package appropriate approvals and forward the offer to the customer within five business days of receiving the proposal.
- Complete the project within the timeframe agreed with the customer.

4.3.3.3 Health, Safety, Environmental, and People (for FSPs)

This KPI is defined around minimising lost time injuries, incidents causing injury to a member of the public and environmental incidents resulting in an infringement notice. Implementing employee health initiatives and keeping employee competencies up to date are also included in the measure.

Health and safety management fits under Vector's strategic objective of operational excellence, and the target or standard for safety excellence is zero injuries. Vector is continuing to work with its FSPs and contracting partners to identify effective ways to further improve the safety of its electrical networks.

4.3.3.4 Customer Experience

This is rated in terms of keeping appointment times, avoiding EGCC rulings against Vector and maintaining Vector's reputation in the media (taking into account adverse weather that may have affected our ability to perform) and implementing behaviour-based customer service training to the agreed plan.

4.3.3.5 Cost Management and Efficiency

The cost management and efficiency KPI depends on invoicing accurately and on time, and providing accurate information to assist Vector with third party damage claims. There is also a target to deliver annual productivity improvements through developing and implementing initiatives that drive efficiencies in either Vector's or the FSP's business.

4.3.3.6 Information Quality

Finally, the information quality KPI is determined by assessing the accuracy, completeness and timeliness of updates to Vector's information systems, before, during and after the completion of works. Special consideration is given to safety or other significant incidents caused by any network assets not being shown in the correct location in GIS.

Vector Target

The target times for updating Vector's information systems are:

Services	3 business days after livening
Subdivisions	2 weeks after livening
Faulted asset repairs	3 business days after livening
Asset replacements	3 business days after replacement
Fault data	1 business day after fault resolution
Zone Substations	2 weeks after livening

4.3.4 Health, Safety and Environment

Vector's policy and overall approach to Health, Safety and Environment (HS&E) is described in Section 8.

In addition to the specific performance measures relating to HS&E that have been put in place with the FSPs, Vector monitors electricity-related public safety incidents and incidents arising from its employees. These incidents are revised monthly to ensure lessons are captured and where appropriate, corrective actions are implemented.

Figure 4-33 below shows the long-term trend in lost time injuries at Vector (including Vector staff, contractors and FSPs) over the last six years. The figures include both Electricity and Gas network activities.

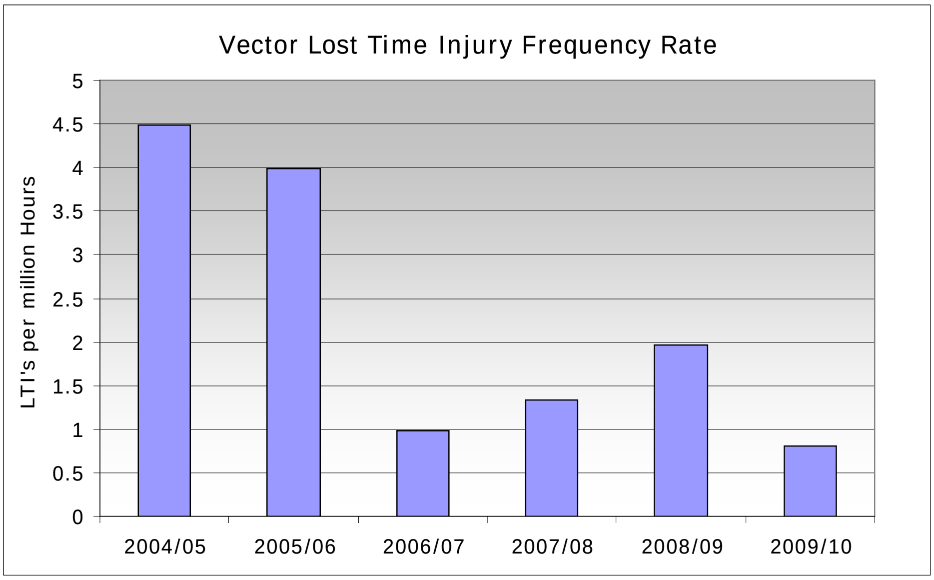


Figure 4-33 : Lost time injuries at Vector (including gas networks)

Note that activities performed in the Wellington Electricity network (divested on 23 July 2008) are also included in this data.

Environmental incidents are also reported, recorded and investigated with any learnings and improvements shared with the FSPs at the safety leadership forum.

Vector Target

Vector's overall health and safety target is to achieve zero lost time injuries.

Vector's environmental target is full compliance with all requirements from local and regional councils to have no prosecutions based on breaches, environmental regulations or requirements.

To progress towards Vector's target of zero injuries in the workplace, Vector is placing an increased focus on ensuring hazards, where ever possible, are eliminated during the design phase, Vector's policies and procedures assist the workforce to deliver the right action at the right time, and to focus on personal behaviours to encourage an individual and team safety culture.

Electricity
Asset Management Plan
2011 – 2021

Network Development Planning – Section 5

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

5. Network Development Planning

Network development relates to growth initiatives which:

- Extend Vector's electricity network to developing areas;
- Increase the network capacity or supply levels of the existing network to cater for load growth or changing consumer demand;
- Provide new customer connections; and
- Address the relocation of existing services when requested by customers, utilities or requiring authorities.[1]

5.1 Network Development Processes

Vector's network development process involves the planning of the network, solutions identification, budgeting, solution prioritisation, programme and implementing the planning solutions. This process has been reviewed by independent external specialists in the past few years with only minor improvements being suggested. These suggestions have been included.

5.1.1 Network Planning Process

Vector's primary objectives in network planning are to identify foreseeable network related security,[2] capacity and power quality (PQ) (voltage levels and distortion) problems and solve in a safe, technically efficient and cost effective manner. These include:

- Power quality, security or capacity issues that may prevent Vector from delivering its target service levels;
- Adequacy of supply to new developments or areas requiring electricity connections; and
- The need to relocate assets, when reasonably required by third parties.

The diagram in Figure 5-1 shows the high level planning and programme implementation processes.

Knowledge of asset capacity and accurate demand forecast enables an assessment of the network's ability to deliver the required level of security and service. Input data comprising past demand information, forecast customer growth, technology trends, demographics, and industry trends are used to produce the demand forecast.

[1] The main requiring authorities are local authorities, ONTRACK and NZTA.

[2] "Security" as used in a planning context means the security of the electricity supply i.e. the likelihood that supply may be lost.

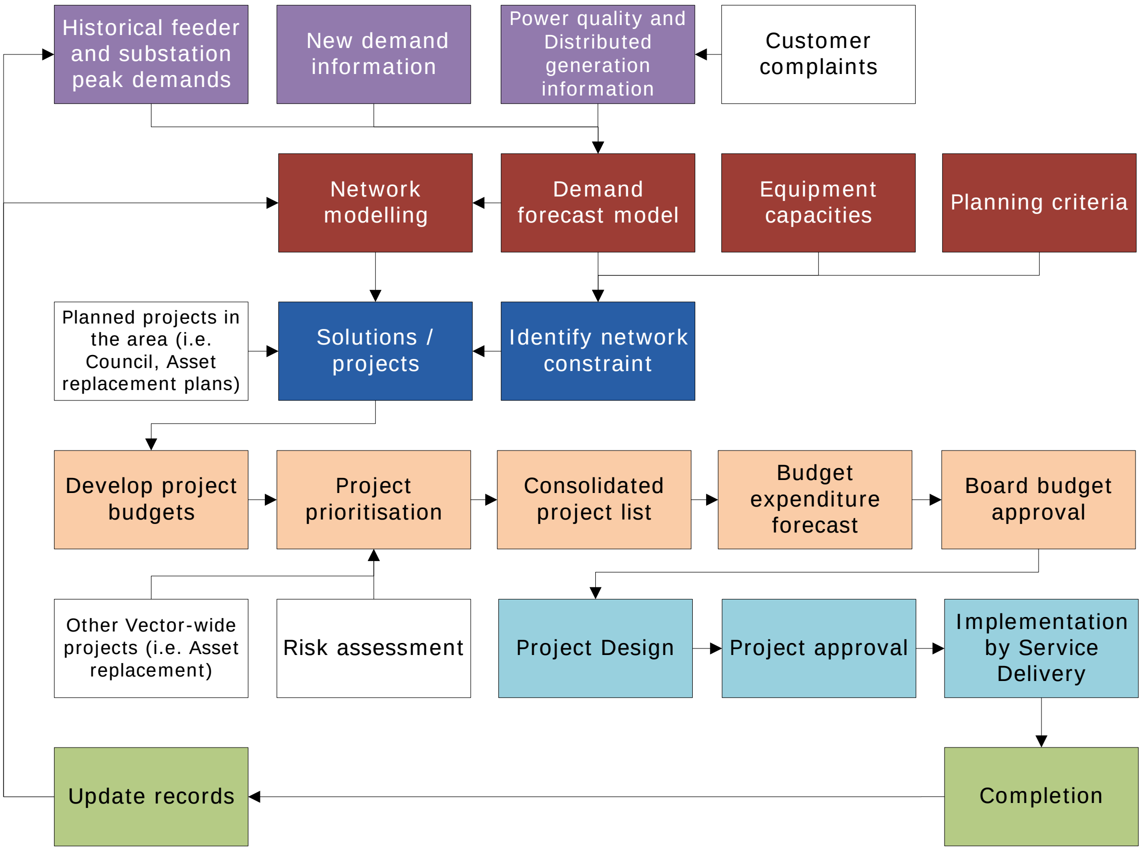


Figure 5-1 : Network development and implementation process

Network capacity and security constraints are addressed with a combination of both asset or non-asset solutions, where the optimal solution may not necessarily result in network augmentation. In evaluating the solutions, the following factors are considered:

- The demand forecast and asset capacity to test against the security criteria to ensure the suitability and adequacy of solutions for security or capacity issues;
- Demand-side options such as load management or customised pricing to reduce demand on the network;
- Automation to expedite load transfer and restoration times;
- Capacitor banks to boost low voltage and provide added capacity in low growth areas;
- Upgrade of specific network assets to relieve capacity constraints eg. upgrade a transformer connection to increase the overall capacity of a substation;
- Using the diversity arising from different load profiles (residential/ industrial/commercial) to reduce overall demand;
- Targeted solutions to satisfy the specific requirements of customers eg. provide a higher security supply across two GXP's to meet customers' security needs;
- Ensuring that, where possible, short-term solutions will meet the long-term needs without asset stranding;
- Considering any operational constraints created by a particular solution eg. a solution may solve a security issue but impose a higher SAIDI penalty under fault conditions;
- Evaluating projects taking into account the time-value of money to ensure the optimal solution is promoted;

- Coordinating the network development programme with other work programmes such as asset replacement to achieve synergy benefits;
- Avoiding reputation damage and consequential financial loss arising from the loss of supply to customers;
- Reviewing major assets due for retirement to ensure their direct replacement meets future network needs; and
- Ensuring recommended solutions are commercially appropriate.

5.1.2 Project Implementation

An effective delivery of the capital works programme, based on an end-to-end delivery process has been established between Vector's Asset Investment (AI) and Service Delivery (SD) groups. The process tracks each project from conceptual design through to site construction and commissioning.

5.2 Planning Criteria and Assumptions

Network development planning is concerned with delivering network performance based on the availability of reserve capacity to a level of risk acceptable to the board, or as agreed with customers. Vector has a number of key policies and standards underpinning its network planning approach. These policies and standards cover the following areas:

- **Service level:** Established as part of the use of network agreement with retailers and customers. The service levels reflect expected restoration timeframes and fault frequencies;
- **Network security:** Vector's security standard specifies the minimum levels of network capacity necessary (including levels of redundancy) to meet the service level;
- **Technical standards:** Ensure optimum asset life and performance is achieved. The technical standards ensure capital cost, asset ratings, maintenance costs and expected life are optimised to achieve overall lowest cost for Vector. Standardisation also reduces design costs and minimises spare equipment holding costs leading to lower overall project costs; and
- **Network Standards and Distribution Code:** These include the standards necessary to allow the connection of customers to the network. They include aspects of network design including subdivision design, acceptable fault levels, voltage levels, power factor, etc to ensure safety while meeting expected service levels.

These key documents are based on the following principles:

- All network assets will be operated within their design rating to ensure they are not damaged by overloading;
- Network assets will not present a safety risk to staff, contractors or the public;
- The network is designed to meet statutory requirements including acceptable voltage and PQ levels;
- Customers' reasonable electricity capacity requirements will be met.[3] In addition, the network is designed to include a prudent capacity margin to cater for foreseeable near term load growth;

[3] This includes customers with no- standard requirements, where special contractual arrangements apply.

- Equipment is purchased and installed in accordance with network standards to ensure optimal asset life and performance;
- Varying security standards apply to different areas and customer segments, broadly reflecting customers' price/quality trade-off; and
- Network investment will provide an appropriate commercially realistic return for the business.

5.2.1 Planning Approach

Normal deterministic approach to planning accepts an n, n-1[4], etc level of security. This approach ensures there is a clear understanding of the availability and capability of supporting network assets to meet the network demand in the event of a network fault.

Vector has accepted a marginally lower level of security for certain parts of the network, such that supply cannot be maintained at all times following a fault (for a very small proportion of the time, during peak demand periods). The application of this criterion is shown in the security standards table in the following section (Table 5-1).

The purpose of this approach is to support more efficient network reinforcement investments. The combination of maximum demand and security standards set the design threshold that triggers the need for network reinforcement. By accepting the small risk not sustaining supply should a fault occur exactly at peak times, the design maximum demand can be materially reduced.[5] This offers significant opportunity to improve asset utilisation and defer network reinforcement.[6]

5.2.2 Network Planning Standards

The key standards relevant to Network Planning are summarised below.

5.2.2.1 Security Standards

The security standards are summarised in Table 5-1.

Network element	Load type	Primary voltage	Load Magnitude	Security limits	Ability to meet demand after outage (% of year)	Customer interruption duration for outage
Bulk supply substation	CBD (Quay, Hobson, Liverpool)	110kV	Any	N-1 N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban (Wairau, Kingsland)	110kV	Any	N-1	100%	Nil
Sub-transmission circuits	CBD (Quay, Hobson, Liverpool)	110kV	Any	N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban (Wairau, Kingsland)	110kV	Any	N-1	100%	Nil
	CBD (Quay, Hobson, Liverpool)	22kV	Any	N	Nil	Repair time
	Urban & Rural	33kV, 22kV	> 10MVA	N-1	95% (residential), 98% (commercial/ industrial)	< 5 min

[4] An n-1 security level, for example, means supply will still be maintained after one network component fails.

[5] The extent of reduction depends on the duration for which such a risk would be deemed acceptable.

[6] The conventional deterministic approach requires sufficient asset capacity to meet full peak demand, even if this occurs for a few half hours per year.

Network element	***Load type***	***Primary voltage***	***Load Magnitude***	***Security limits***	***Ability to meet demand after outage (% of year)***	***Customer interruption duration for outage***
	Urban	33kV, 22kV	< 10MVA	N	Nil	Repair time
		Backstop capacity is, however, provided through the 11 kV distribution network and supply will be restored by manual field switching in accordance with times set out in the Service Level Standards, subject to the 95% (residential) and 98% (commercial/industrial) capacity availability figures.				
	Rural	33kV, 22kV	< 10MVA	N	Nil	Repair time
Zone substation	CBD (Quay, Hobson, Liverpool)	22kV	Any	N-1 N-2	100% (1st outage) 100% (2nd outage)	Nil (1st outage) < 5min (2nd outage)
	Urban & Rural	33kV, 22kV	> 10MVA	N-1	95% (residential), 98% (commercial/ industrial)	< 5 min
	Urban	33kV, 22kV	< 10MVA	N	Nil	< 5 min
		Backstop capacity is, however, provided through the 11 kV distribution network and supply will be restored by manual field switching in accordance with times set out in the Service Level Standards, subject to the 95% (residential) and 98% (commercial/industrial) capacity availability figures.				
	Rural	33kV, 22kV	< 10MVA	N	Nil	Repair time
Distribution feeder	CBD	22kV, 11kV	Any	N-1	100%	< 2 hrs
	Urban	11kV	> 1MVA overhead > 400kVA underground	N-1	95% (residential), 98% (commercial/ industrial)	< 3 hrs Northern < 2.5 hrs Southern
	Urban	11kV	< 1MVA overhead < 400kVA underground	N	Nil	Repair time
	Rural	11kV	> 2.5MVA overhead	N-1	95%	< 6 hrs Northern < 3 hrs Southern
	Rural	11kV	< 2.5MVA overhead	N	Nil	Repair time
Distribution substation	CBD	11kV	Any	N	Nil	Repair time
	Urban	11kV	Any	N	Nil	Repair time
	Rural	11kV	Any	N	Nil	Repair time

Notes:

Circuit rating is set by the post contingency, healthy circuit, cyclic rating.

Applies to "credible contingencies" only

Table 5-1 : Network security standards

Security standards are specified by broad groupings based on load magnitude, encompassing sub-transmission and distribution. Security levels at each of these levels are typically in line with international industry best practice. Where the highest level of security is required, multiple concurrent faults can occur before customer supply is lost. In Vector's case, this level of security is reserved solely for the sub-transmission within the Auckland Central Business District (CBD).

Outside the CBD a higher level of risk is accepted. The network is designed such that for commercial or industrial areas, should a sub-transmission, distribution feeder or zone substation fault occur, supply can be fully restored 98% of the time.[7,8] For 2%

[7] Restoration may, in some instances, lead to a short (less than 5 minute) outage, to allow network switching.

of the time, at peak demand periods, it may not be possible to fully restore supply until repairs have been carried out. For residential areas full capacity can be supplied for 95% of the time.

As noted above, this approach implies a security level marginally lower than the more conventional N-1 design approach, but from a network utilisation and economic efficiency perspective, it is far superior. The added risk that an outage may occur during peak demand periods is minor.

An exception is made to this security standard for urban or rural feeders with low demand[9], where the installation of redundant assets cannot be economically justified.[10] In these cases restoration of supply generally requires rectifying the fault.

Zone substation security levels are based on a threshold of 10MVA. For substations with a demand smaller than 10MVA, single transformer substations are used that only provide an N level security. In these cases, the design philosophy is to restore supplies after a fault from adjacent zone substations, using the 11kV distribution network backstop capability, up to the maximum level of 10MVA. (Zone substations with demand higher than 10MVA will have more than one power transformer, providing N-1 security.)

Another important consideration in the security standard is the design restoration times (as distinct from service level targets). These relate to the time required to restore supply after a network fault, to restore full capacity. For the sub-transmission networks, these times are generally short (see Table 5-1), and are based on automated switching that will transfer load automatically following a fault, or through remote switching initiated by Operations staff. At distribution feeder and substation levels, automated switching facilities are not as readily available and manual field switching may be required, resulting in longer possible restoration times.

5.2.2.2 Accepted breaches of the security standards

Vector accepts a small number of instances where the distribution network security standards will be breached, which affect our network designs. These generally relate to one of the following four situations:

a. Loss of bulk supply to all or part of Vector's network. Vector cannot realistically mitigate against a major loss of generation or transmission capacity. Such events will, therefore, lead to outages on the distribution network.

b. The network development programme is generally based on forecast demand estimates and investments are made as far as realistically possible on a just-in-time principle. This approach seeks to avoid security breaches arising from growing demand, while at the same time avoiding too-early investment and hence under-utilised assets. In some instances, however, external factors (such as more load growth than foreseen at the time of planning) may lead to the timing of investments not exactly coinciding with the moment at which a security standard is exceeded. Security standards may, therefore, be breached until commissioning of the new required assets takes place.

c. The security standards are based on an optimal trade-off between network reliability and the cost of providing electricity distribution services.[11] This, in

---

[8] Note that this applies to sub-transmission, zone substation or feeder faults only. Should a fault occur on a distribution substation or on the low voltage network, the same level of network redundancy does not exist, and outages may be experienced while fault repairs are carried out.

[9] <4MVA total peak load for areas fed from overhead circuits and <400kVA for areas fed from underground networks. The difference in load magnitude reflects the average time required to restore supply on overhead and underground networks.

[10] Unless specifically required by customers, in which case special commercial arrangements are made to recover the additional costs from the requiring customer(s).

turn, requires an evaluation of the energy at risk during credible outage events and the cost involved to reduce the risk. There are (a small number of) parts of Vector's distribution area where the provision of our standard security standards would be highly uneconomic. These are generally areas with very low consumer and/or consumption density, often remote from our main distribution network. To upgrade supplies to these areas to Vector's normal security standards would, therefore, require material additional recovery contributions from the customers affected. For these areas, the security standards may, therefore, be relaxed.[12,13]

d. There are a number of credible, but highly unlikely contingency events, that may occur on a distribution network, that would almost inevitably give rise to extensive and extended outages. These are the so-called HILP (high-impact, low-probability) events that would have a widespread impact, but would be inordinately expensive to avoid (if indeed possible) and where the likelihood of their occurring is so low this expenditure cannot be realistically justified. HILP events that Vector, therefore, accepts which could lead to major power outages include:

- Destruction of the Penrose/Liverpool tunnel and all circuits within. This would leave the CBD supply exposed[14];
- Failure of a tower or structure on the double circuit 110kV overhead line feeding Wairau substation in the North Shore, which would leave a shortfall in supply capacity for the North Shore[15];
- Loss of multiple transmission/ sub-transmission cables in a common trench. Vector has a number of double circuits feeding zone substations which share a common trench. In theory, a single event could, therefore, damage more than one circuit[16];
- Complete failure of a 110kV, 33kV, 22kV, or 11kV busbar at a substation, which would affect multiple circuits[17]; and
- Total loss of a zone substation (single or multiple transformers) through a force majeure event such as an earthquake, flood or plane crash.[18]

For all these cases, the risks are managed to the fullest practical extent possible and contingency plans are in place to minimise the impact of the event.

---

[11] In several surveys, carried out over an extended period, Vector's customers indicated they are satisfied with existing reliability levels and do not want Vector to improve on this if it means increasing the price of distribution services.

[12] The difference in supply reliability for different parts of the network are also reflected in the security standards themselves, but there may be instances where even these standards have to be further relaxed to provide an economic supply to consumers.

[13] Customers who do require a higher level of supply reliability have the option to negotiate a special contract with Vector, that would reflect the extra cost involved to provide this through their line charges or through an upfront investment requirement.

[14] Work is underway for the creation of a new GXP at Hobson St in the CBD. Once this is in place (planned for mid 2014) the risk will be fully mitigated.

[15] Work is underway for the creation of a new GXP at Wairau Park substation. Once this is in place (planned for mid 2013) the risk will be fully mitigated.

[16] In practice, these circuits are well separated and instances of more than one underground circuit being damaged through one incident are extremely rare. The cost of providing redundant trenching is prohibitive.

[17] The busbar is the point in a substation to which all circuits are connected and while a degree of redundancy and busbar protection can be provided, this is not practical or economically feasible in the great majority of cases.

[18] All substations are designed to stringent earthquake and flood level requirements, but it is not possible to completely mitigate against major external events. This has been graphically illustrated in the recent Christchurch earthquake.

5.2.2.3 Network Configuration

Vector takes supply from the transmission grid at the various GXPs. The sub-transmission network of the two network regions at Vector has been developed using different configurations, due to legacy network designs. Dual radial-fed transformer feeders have been widely used in the Southern region whereas a mesh configuration has been the dominating Northern region design.

There are a number of substations in the Northern region equipped with a single transformer. These substations rely on the distribution network to provide the necessary back-up to maintain the required security level. The distribution network (in both regions) is configured in radial formation. The radial feeders are interconnected via normally open switches to provide backstops from either the same substation or a neighbouring substation.

5.2.2.4 Voltage Limits

Sub-transmission voltages are nominally 110kV, 33kV and 22kV in line with the source voltage at the supplying GXP. The voltages used at MV distribution level are nominally 22kV, 11kV and 6.6kV (currently being upgraded to 11kV). The LV distribution network supplies the majority of customers at nominally 230V single phase or 400V three phase. By agreement with the customers, supply can also be connected at 11kV, 22kV or 33kV.

Regulation 53 of the Electricity Regulations 1997 requires that standard LV supply voltages (230V single phase or 400V three phase) must be kept within +/-6% of the nominal supply voltage, calculated at the point of supply except for momentary fluctuation. Supplies made at other voltages by agreement with the retailer or the customer and must be kept within +/-5% of the nominal supply voltage except for momentary fluctuation, unless agreed otherwise with the retailer or the customercustomers.

Design of the network takes into account the voltage variability due to changes in loading and embedded generation under normal and contingency conditions.

5.2.2.5 Fault Level

A fault on the network would generally result in high current flowing into the faulty component. The maximum current that can flow determines the required fault level of components. The effects of a fault current impact on the network component in the following manner:

- **Heating effect:** The fault current creates localised heating in the vicinity of the fault. The magnitude of the heating varies in proportion to the duration of the fault, resistance of the network component and the square of the fault current;
- **Magnetic force:** The large magnetic field caused by the fault current manifests itself as mechanical stress on the components leading to mechanical failure; and
- **Arc breaking:** The ability of the network isolation devices on the network to isolate the fault and interrupt the fault current.

Network components have to be designed to withstand the mechanical forces and heating effects that will be experienced during fault conditions. If, during a fault, fault levels are exceeded, this can lead to catastrophic failure of equipment with severe associated health and safety risks. Equipment is, therefore, purchased to meet the maximum fault levels (prospective fault level) expected on the network. These are shown in Table 5-2.

Supply Voltage	Prospective Fault Current
110kV	31.5kA
33kV	25.0kA
22kV sub-transmission	25.0kA
22kV distribution	20.0kA
11kV distribution	13.1kA

Table 5-2 : Fault levels

Fault levels are determined through a combination of factors, mainly by the fault capacity of the bulk supply points, the impedance between a fault and the point of supply and the type of fault that occurs. Vector's distribution network is designed and built around the values stated in the above table. Should the fault levels change in future[19], it will likely involve very significant network upgrade expenses. (In Section 2.3.2.4 the actual calculated fault levels at Vector's zone substations are listed.)

Fault levels can also be exceeded in localised areas where substantial levels of distributed generation (including solar cell generation) are connected to the distribution network. Vector, therefore, has to monitor the impact of generation devices and limits exist on how much capacity can be connected to the network (without requiring investment in fault limiting devices).

5.2.2.6 Equipment Capacity

All equipment (transformers, cables, switchgear, etc) has a rated load carrying capacity depending on the demand characteristics (flat, fluctuating or cyclic) and the environment in which the equipment operates (ambient temperature, proximity with other equipment, ability for heat dissipation, etc.). The overall capacity of a circuit is based on the capacities of the individual components.

Where load patterns allow, the circuit capacity takes into account cyclical or short-term capacity ratings, rather than the flat, long-term rating. This allows smaller equipment to be used in areas where peak demands do not persist for extended periods.

Peak and cyclical demands are, therefore, taken into account in Vector's demand forecasts.

5.2.2.7 Power Factor

The Connection Code promulgated by the Electricity Commission (now the Electricity Authority) as Part F of the Electricity Governance Rules (EGR) requires the power factor of the load at Henderson, Albany and Wellsford GXPs be maintained at unity during peak demand times. For the other GXPs, the power factor is required to remain at a minimum of 0.95 lagging.

The ability to maintain unity power factor is unachievable in practice, and not economically efficient when compared with the small benefit it brings[20]. Vector has

[19] This is outside of Vector's control.

[20] Due to the fluctuating nature of electricity loads (even at peak), the difficulty of fine-tuning reactive compensation schemes, and the sophisticated in-time response that will be required to remain operating at even near unity power factor, the current ruling is impractical. On top of this, it is likely to be very expensive, which may lead to material increases in electricity pricing to our customers.

been granted an exemption[21] from the System Operator pending the agreement of a practical conclusion of the issue.

5.3 Planning Methodology

In all cases, effective distribution network design requires consideration of (a) the forecast demand, (b) the service standards required, and (c) the capacity of equipment, including consideration of the impact of the environment in which the equipment will operate.

- Vector's service standards are discussed in Section 5.2.
- An effective demand forecast model should provide a sufficiently accurate picture of future demand growth to allow investment decisions, and the timing thereof, to be made with a high degree of confidence.
- The methodology used to assess equipment rating should reflect the true capacity of the equipment under field conditions.

It is important that each of these three components is developed independently. This helps to provide planning and investment consistency and to avoid expedient, short-term decisions with a potentially negative longer-term impact.

5.3.1 Electricity Demand Forecasting

Vector has commissioned Sapere Research Group to review our existing demand forecasting technique and to provide recommendations for enhancing our forecasting model and methodology.[22] The advanced stages of this work are still underway, but the initial findings supports the demand forecasting approach that Vector has historically followed.

For forecasting purposes it is useful to split demand into that arising from two distinct categories – the mass market (residential and small commercial ICPs) and large consumers (industrial and large commercial).

5.3.1.1 Forecasting for large customers

For large consumers, demand is driven by the nature and size of the consumers, and their operating cycles. These connections are relatively few in number but, given their size, can have a major impact on demand, especially at a localised level. The individual demand patterns for these customers tend to be relatively constant over time, only changing materially if operational patterns alter significantly, or extensions (or deletions) to the installations are made.

Peak demand forecasts for this group, therefore, assume a constant base profile. Overlying this base, stepped demand changes are added or subtracted. The demand steps are based on the expected connection of new large customers (or disconnection of existing customers) or material operational changes at existing customers. The size of the forecast discrete steps is based on information gleaned about the individual connections.

Accurate demand forecasting for the large customer category, therefore, relies on an understanding of existing demand patterns, and advance knowledge of discrete load changes. The latter requires ongoing discussions with existing and potential large customers to ascertain their future plans. New customers, with significant capacity

[21] The exemption expires on the 1 April 2013 but is conditional on Vector meeting a power factor of 0.975 lagging or 0.97 leading, at these sites during system peaks.

[22] The study is also addressing customer number and energy volume forecasts.

requirements, will generally approach Vector well in advance of the time the connection is required[23].

In exceptional instances, where Vector is notified in advance of the future development of areas specifically set aside for industrial or major commercial developments, some allowance may be made for demand growth even if actual individual capacity requirements are not yet known. This would generally only be where planned bulk supply or sub-transmission developments would be materially influenced by such developments, and where an acceptable degree of certainty about the developments exists.

5.3.1.2 Forecasting for mass market customers

The dominant factors driving mass market demand over time are connection numbers, the type of connections and the average individual electricity demand curve[24] associated with the different types of connections (which varies between areas).

Residential connection numbers closely follow population trends, although the average number of people per connection can vary over time and between areas. Small commercial ICP numbers also tend to follow population size, although the relationship appears to lag somewhat. Based on Vector's analysis[25], population growth and hence ICP numbers on a network-wide as well as GXP-wide level demonstrate a high correlation with time (i.e. growth in customer numbers tend to be linear when viewed over a long period). The average demand curves for customers vary between the types of customer and between different areas. There is also a material difference between summer and winter demand curves. However, the curves themselves have remained remarkably consistent over time and for the purpose of forecasting over the AMP planning window demand can reasonably be assumed to remain constant[26].

There are some further statistically significant factors that influence short-term individual demand, such as weather patterns and economic cycles. However, the predictive value added by considering these factors in addition to ICP numbers and historical average demand curves, especially for the longer term view required for network investment planning, is small.[27]

ICP forecasts are, therefore, the primary factor for mass market electricity demand forecasts. These forecasts, prepared by the Vector Commercial team, are largely based on population growth data provided by Statistics New Zealand household projections. Vector's distribution area is divided into small pockets of land aligning with Census Area Units (CAUs). Population, employment and load composition (eg. proportion of residential and commercial/industrial) is determined per CAU area and are pro-rated across the feeders supplying the particular CAU.

The average demand per ICP for an area is derived from historical demand levels, and is assumed to remain constant for the planning period. The average figure is reviewed on an annual basis.

[23] Or run the risk that the required capacity may not be available at the time they want to connect.

[24] Note that the term "demand curve" in an electrical engineering context refers to the maximum actual electricity consumed, measured over time, usually shown in specific time intervals. (See Section 2.2 for examples.) It is not to be confused with the economist interpretation of a demand curve (which is usually read in conjunction with a supply curve).

[25] Also supported by that of Sapere.

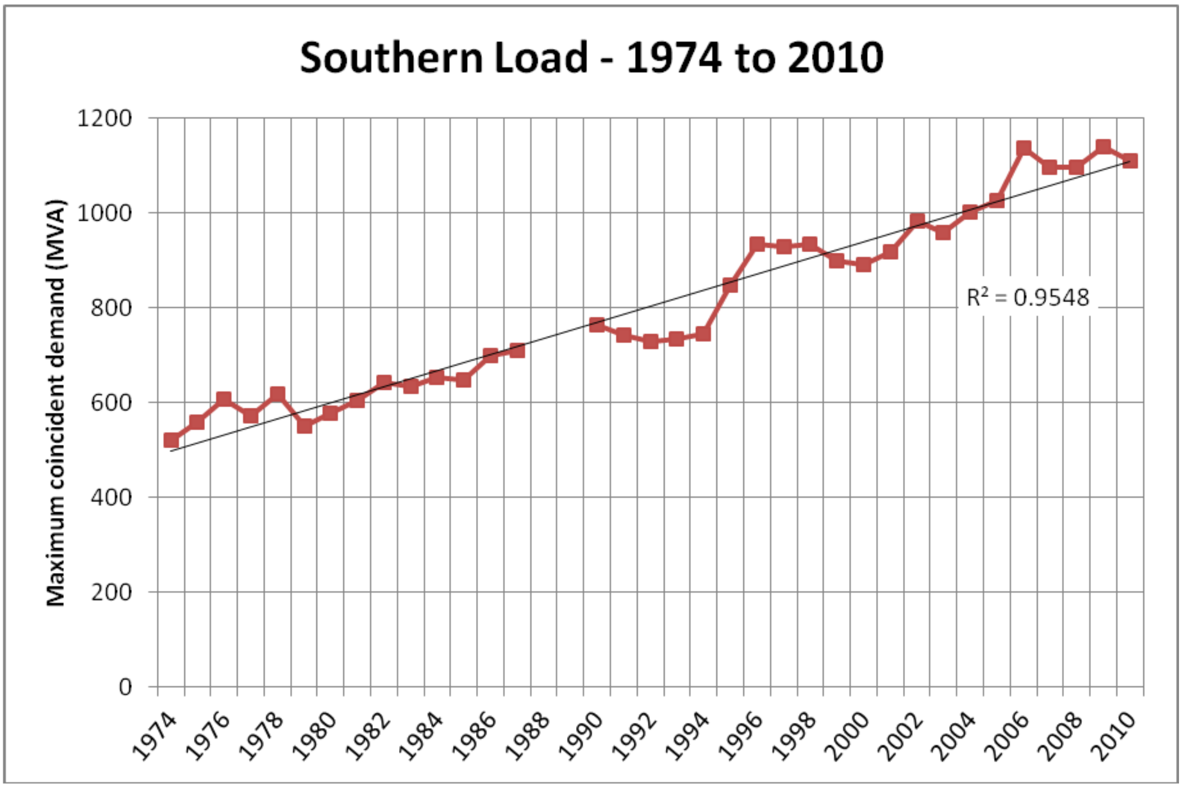
[26] There is some evidence of minor growth in the average demand curve in some areas, or of a shift from winter to summer peaks, but this is not sufficient to have a material impact on investment decisions over the forecasting period.

[27] In addition, forecasting these external factors with an acceptable degree of accuracy is problematic.

5.3.1.3 Long-term observed electricity demand

In Figure 5-2 and Figure 5-3 below the long-term demand growth on the Auckland and Northern distribution networks is indicated. As will be noted, although there are significant short-term fluctuations in demand, over time the growth is remarkably closely correlated with time (R^2 levels in excess of 95%). Over this period the population in Vector's supply areas has grown at a relatively linear rate as well. The figures, therefore, confirm the strong relationship that exists between electricity demand and population, and by implication ICP numbers. The trends also indicate that over time, at a highly aggregated network level, the influence of large customers on demand also tend to grow with population levels.

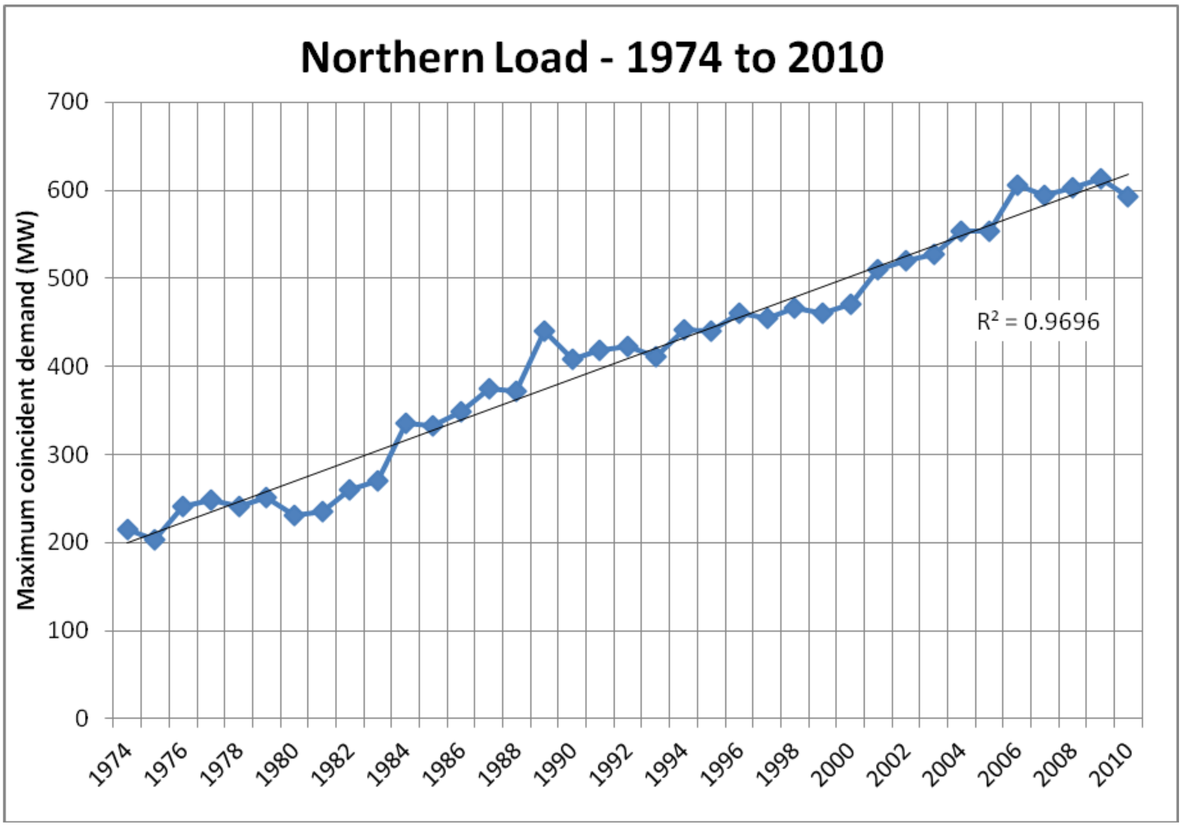
The demand trends could change over time, but such changes are likely to be very gradual and are unlikely to have a material impact on the short to medium-term planning window.



Notes : (a) Due to data problems, demand for 1988 and 1989 was not available

(b) The indicated correlation is with time

Figure 5-2 : Southern electricity network demand trend



Note : The indicated correlation is with time

Figure 5-3 : Demand forecasting at a network or GXP level

5.3.1.4 Demand forecasting at a network or GXP level

For forecasting electricity demand at a network- or GXP level, the following factors are important.

- As illustrated in Figure 5-3 above, the historical demand growth trends on the Vector network has been remarkably linear over time. Although the fluctuations around the linear growth trend are material, they tend to be relatively short-term in nature – certainly much shorter than the average life of electricity distribution assets.

  The results are replicated at a GXP level[28].

- Vector is continually monitoring emerging trends in energy consumption and appliances. At present, we have not identified any factor that should materially influence average individual peak consumption in the near future.[29]

- Population forecasts for Auckland indicate a relatively constant growth rate for the next 20 years.[30]

Given the above, Vector believes that asset investment decisions at a network or GXP-level can be realistically based on assuming a linear demand growth pattern, using

[28] There are incidents when major load shifts at a GXP level can occur – for example when a new GXP is connected to the network – but these are infrequent, discrete step-changes which can be relatively easily accounted for in the forecasts.

[29] This is in the absence of major expansion of load shedding schemes, or incentives for consumers to reduce peak demands.

[30] At the time of preparing this AMP, it is not yet clear whether the Christchurch earthquake would result in a noticeable difference in the Auckland population or electricity demand levels. This situation will be monitored and the forecasts adapted accordingly.

historical growth rates as basis. Investments at this level would typically relate to new GXPs, or major sub-transmission reinforcements.

5.3.1.5 Demand forecasting at a more disaggregated level

Most of Vector's growth-related investments are required at a much more disaggregated network level.

a. Zone substation and feeder level

At a zone substation or feeder level, factors such as changes in the customer mix (for example when commercial activity in a previously mainly residential area increases), or the impact of single large customers can be material on overall forecasting. In addition, as part of network development it is often necessary to reconfigure the network, thus moving customers between zone substations or feeders. The short-term impact of external factors such as weather patterns or economic cycles is also more noticeable at a zone-substation level – where customers often tend to be quite similar in nature, and spread over a limited geographical area, and hence likely to be subject to, and respond to, the same factors in the same manner.

However, even at a zone substation or feeder level of disaggregation, the underlying demand patterns are still relatively stable, and predominantly based on ICP numbers. Taking the above into account, Vector's demand forecasting approach at this level can be summarised as follows.

- In the absence of specific information that would indicate material changes in future demand (such as the addition or removal of a large customer, or a new subdivision planned for an area), future demand is forecast to be based on historical demand trends (with an emphasis on experience over the last five years), while adding the forecast future demand resulting from ICP growth.
- Where substantial additional (or reduced) loads are likely to arise over the planning period, this is superimposed over the underlying demand trend for a substation or feeder. Such loads are generally forecast based on discussions that Vector has with its large customers, developers and consultants about possible forthcoming developments, and an internal assessment is made about the likelihood of such developments. Significant load pattern changes can also occur due to network reconfigurations.
- The potential demand impact of short-term fluctuating factors, such as weather patterns and economic cycles are not individually accounted for, but are taken into account through considering historical demand curves, specifically the potential that these have to add to demand peaks.[31] The degree of redundant supply capacity that exists is also taken into account.
  - For dual transformer substations – where a high degree of supply capacity redundancy exists, future demand forecasts will generally be set at the average of the indicated historical demand trends (a P50 level, or 50% probability of exceedance). This implies a relatively high likelihood that demand may exceed the N-1 capacity (or security standard) of a substation for a short period prior to it being reinforced. However, given the available redundancy this is highly unlikely to lead to outages.
  - For single transformer substations, the demand forecasts are set at a P90 level of the indicative historical demand curve range (a 10%

[31] Networks have to be able to adequately cope with peak demand periods, and demand troughs are, therefore, of less interest for planning purposes.

probability remains that capacity may be exceeded). This reflects the lower capacity of these substations to manage higher than rated load – thereby effectively bringing forward the point at which they have to be reinforced.

- Feeders load is forecast on a P50 principle. Forecast demand is matched against spare backstop capacity from adjacent feeders to ensure there is sufficient capacity to meet the security requirements as shown in the Security Standards table (Table 5-1). The ability to move "open-points" and shift load to adjacent feeders ensures that unexpected load caused by short-term effects, such as adverse weather, can adequately be catered for with a P50 model, avoiding a more conservative P90 forecast approach.

- Both summer and winter demand forecasts are prepared. The summer demand forecast is required to reflect the lower network capacity during warm periods;
- Adjustments are made for known, one-off network demand distortions such as brief high load due to load transfers, large load increases/decreases, installation of capacitor banks or embedded generation. Evident errors in historical data are also corrected;
- Network-connected, embedded generators are assumed to maintain current operating patterns. The impact of new embedded generation will be reflected in forecasts as information becomes available. Existing generation at landfill sites is monitored and decommissioning plans are reflected in the demand forecast;
- Vector has a load management system that can directly influence demand. However, at present the load management system is predominantly used to shed load during contingency conditions or where there is a short-term risk that network capacity may be exceeded;
- The impact of emerging technologies and associated possible changes in energy consumption patterns are continually being assessed. Vector's best current view on this (see Section 3 for a discussion) has been accounted for in the demand forecasts.[32] Vector also conducts what-if analyses on the demand forecasts to test the impact on investment plans should material changes in energy consumption occur. Realistic scenario assumptions do not indicate a need for material changes in the current investment plan.

b. Distribution transformer and low voltage level

At the lowest level of disaggregation load forecasting is generally only done at the time of installing the assets – based on the anticipated final number of customers that will be connected. Should demand exceed the capacity of installed assets, the assets will be replaced or the local low-voltage network will be reinforced.

In Figure 5-4 a schematic overview is provided of Vector's forecasting approach, at different levels of network aggregation. A spreadsheet based model has been developed in which the actual forecasts are currently prepared. (This will be upgraded during 2011, based on the recommendations of the Sapere study.)

[32] At present, the only technology potentially causing a material impact on demand within the planning period is the increased use of heat pumps.

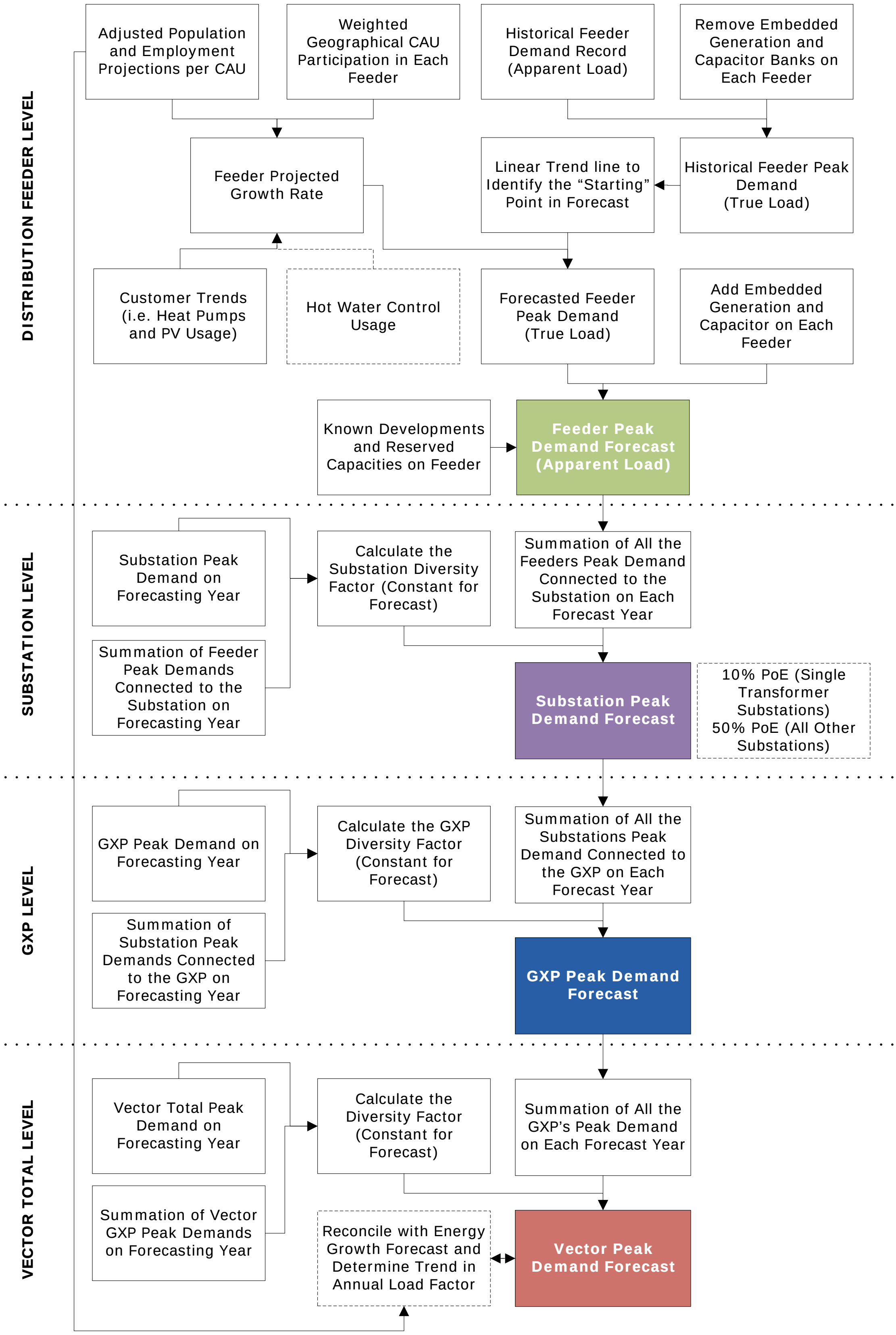


Figure 5-4 : Schematic representation of the Vector load forecasting process

In spite of the due care taken by Vector in preparing demand forecasts, given the inherent uncertainties associated with it, and the short-term fluctuating nature of demand, consistently achieving an optimal investment point for network reinforcements is unlikely and situations may, therefore, still arise where security standards are breached (for short periods). However, with the level of redundancy and switching flexibility that exists in the network, the limited ability to shed load, and the relatively slow rate of growth, this does not represent a material risk to network operations or reliability.[33]

5.3.2 Planning under Uncertainty

A number of precautions are taken to mitigate the risks of long-term investments in an uncertain environment. Apart from normal business risk avoidance measures, specific actions taken to mitigate the risks associated with investing in networks include:

- **Acting prudently**: Make small incremental investments and defer large investments as long as reasonably possible (reinforce distribution feeders rather than build zone substations). The small investments must however conform with the long-term investment plan for a region and not lead to future asset stranding;
- **Multiple planning timeframes:** Produce plans based on near, medium and long-term views. The near term plan is the most accurate and generally captures load growth for the next three years. This timeframe identifies short-term growth patterns and leverages off historical trends. It allows sufficient time for planning, approval and network construction to be implemented ahead of the new network demand.

  The medium-term plan looks out ten years, capturing regional development trends such as land rezoning, new transport routes and larger infra-structure projects. The medium-term plan also captures society's behavioural changes such as the adoption of heat pumps and new technologies (eg. PV panels, electric vehicles (EVs, etc) or global trends (eg. climate change, energy conservation, etc).

  The long-term plan looks at growth patterns within the region at the end of the current asset lifecycle, say 40 years. A top-down approach predicts probable network loads within the region and superimposes zone substations and GXPs to meet these loads. The objective is less to develop accurate load forecasts and more to provide a long-term development plan identifying future zone substation and GXP requirements;
- **Review significant replacement projects:** For large network assets, rather than replace existing end-of-life assets with the modern equivalent, a review is carried out to confirm the need for the assets, the size and network configuration that will meet Vector's needs for the next asset lifecycle; and
- **Use of non-network solutions** where possible, to improve network utilisation and capital efficiency. Load control or shifting is a good example – moving demand from one time segment to another or from one feeder or substation to another without adversely affecting the customer, while deferring the need for new network investment.

The larger customer initiated projects can have a significant impact on the demand forecast and, therefore, the timing of capital investments. However unlike network growth projects where the timing is determined by Vector, the timing of the customer projects are dictated by the customer. Except for the near term projects, there is often a high degree of uncertainty both in terms of required demand and the date the demand will be required. Including new customers' demand forecasts without

[33] A lower-risk approach could be to bring investments somewhat forward from the programme indicated by consideration of the demand forecasts and required security levels. Vector's analysis indicates that this would in general not be economically prudent.

critically evaluating these, very often leads to an over-optimistic assessment of forecast demand, which if followed, would lead to a premature investment in additional capacity.

Vectors approach to these projects is to apply a weighting to the customers demand expectations, based on an assessment of the likelihood of the project proceeding in any particular year. This weighted demand assessment is included in the demand forecast. While some projects will still not proceed in the expected year, this tends to balance out the conservative provision included for those that do proceed.

5.3.3 Impact of Embedded Generation

Large embedded generation sites exist at Redvale (landfill gas), Rosedale (landfill gas), Greenmount (landfill gas), Whitford (landfill gas), Auckland Hospital (CHP) and Watercare (Mangere). Other currently embedded generation is either relatively small and does not have an impact on the network, or is designed to operate as an isolated power supply not coupled to the network. Where it does impact on the network, the generation is included in the load forecast model as described in Section 5.4.

Table 5-3 summarises the generation applications processed in the 12 months to the end of 2010.

Generation Size Range	Number of Applicants
10kW or less	14
Greater than 10kW	4

Table 5-3 : Generation connection applications for 2010

In the longer term, with the price of photovoltaic panels expected to become more affordable, more photovoltaic generation installation is expected at the household level in the next decade. When high concentrations of PV panels are installed, problems such as over voltage and reverse power (potentially causing protection problems) flow could occur. These issues have been reported to occur in overseas jurisdictions where governments subsidise (or force power companies to buy back generation at a heavily subsidised rate) PV installations.

For embedded generation connected to the low voltage network (such as solar PV), the fault currents they impose on the network (LV and MV) are generally negligible. However, for larger embedded generation (typically 500kVA or larger) connected to the MV distribution network, the additional fault current injected by these generators can be significant enough to exceed the fault rating of the local network (such as circuit breakers). As an example, the increased fault level due to connection of the embedded generator at Auckland Hospital has necessitated the installation of a dedicated transformer to supply the Hospital.

Embedded generation connected to weak remote networks (such as rural overhead lines) could cause significant voltage fluctuation to nearby customers as output of the generation fluctuates. Condition of the network upon failure of the generation also needs to be considered as part of the connection approval process as this could significantly affect the network voltage, capacity and security.

For landfill gas generation sites, careful monitoring and planning is needed to ensure availability of gas to generate electricity to supply the area load and alternative supply plans are prepared to cater for the eventual retirement of the generation station due to gas depletion.

Other key consideration in approving embedded generation connection includes protection setting, islanding operation and the presence of upstream auto reclosers.

5.3.4 Network and Asset Capacity

To enable the capacity of the delivery points (zone substations and feeders) to be assessed, it is necessary to a have a reliable assessment of the capacities of the major network components. Major components include:

- underground cables;
- over head lines;
- transformers; and
- switchboards.

Determining the capacities of these network components requires a detailed assessment of each sub-component. (For example, in assessing the capacity of a transformer, ratings of the bushings, tap changer, and other accessories are also assessed to ensure the sub-component with the lowest rating – which determines the overall asset rating - is identified.)

The following paragraphs describe how the capacities of the network components are assessed. In all cases, asset capacities are not only assessed at normal full-load ratings – the cyclical and/or short-term ratings are also determined.

5.3.4.1 Cables

The analysis of MV cable ratings is complex, due to the major influence of external factors such as cable type and circuit configuration, installation practices, surrounding soil composition and moisture content, solar gain, proximity of other circuits and preloading conditions. Vector uses the cable rating modelling tool "CYMCAP", a product of CYME Corp of Canada to perform ampacity and temperature rise calculations for power cable installations. This software tool is used to determine the maximum current power cables can sustain without deterioration of their electrical properties.

5.3.4.2 Overhead Lines

Environmental and operating conditions play a large part in determining the capacity of overhead lines. Factors such as temperature (minimum, maximum, average), wind velocity and solar gain, coupled with initial sag and tension calculations, determine maximum operating ratings, while factors such as humidity, pollution level, altitude and rain levels affect the insulation and support designs. Vector uses the methodology defined in IEEE Standard 738:1993 for calculating conductor ratings.

A computer package called "CONAMP" is used to determine the maximum rating of OH conductors.

5.3.4.3 Transformers

Technical specifications for the purchase of power transformers reflects Vector's network planning standards and network operating practices. Transformer specifications have varied over the years from the very early versions of British Standard BS-171 to the latest Australian Standard AS-2374, resulting in different thermal and loading guides for transformers conforming to the various standards.

Southern region power transformers have been designed around a base rating (usually ONAN) with a two hour extended operating (emergency) rating. The intent of the extended operating range is to provide overload capacity for a limited time to allow time for network switching to mitigate the conditions.[34]

Northern region power transformers were specified following a British standard based on a 12/24 hour rating scheme. This is interpreted as a maximum operating rating without additional overload or emergency rating.

Power transformers purchased since 2004 have been based on Vector Specification ENS-0120 which is an adaption of AS-2374 to Vector's specific requirements. Under this specification, transformers can operate up to 150% of nameplate rating for up to two hours, with a 120% of ONAN for normal cyclic loading.

Regardless of the transformer specification, Vector has three operating temperatures limits:

- Top oil temperature - 105ºC;
- Conductor hot-spot temperature - 125ºC; and
- Metallic part temperature - 135ºC.

Subject to the transformer operating within these temperature limits, the transformer capacities are reviewed in accordance with load profiles to determine whether higher ratings may be achieved without marked degradation of transformer lives.

5.3.4.4 Switchboards and Switchgear

Indoor electrical distribution switchboards and outdoor switchgear are manufactured and tested to varying international and domestic electrical standards. Switchboard testing is based on nominal (environmental) operating conditions whereas switchgear (primarily outdoor apparatus) takes into consideration an extended operating environment.

Switchboards and switchgear on the Vector network can be operated to the manufacturers' nameplate values. These ratings are derived by the OEM type tests performed to the Standards specified when the equipment is purchased.

5.3.5 Project Prioritisation

The planning process results in a list of network projects and non-network solutions. These projects, along with others submitted from other groups (asset replacement, overhead to underground conversions, customer connections etc) are evaluated against a risk matrix to obtain a peer-wise comparison (see Section 9). The risk matrix looks at the consequences of not undertaking the project, by considering wider company factors such as operational, health and safety, environmental, legal, financial, reputational and regulatory risk to develop a "project necessity" rating or priority rating for the project.

The resulting list of projects becomes an input for the capital works programme. For network growth projects, the project priority is generally in the following order (from high to low):

- Avoiding capacity breaches that could lead to asset damage/eliminating unsafe situations;
- Avoiding breaches of electricity regulations (such as LV levels, etc);
- Avoiding capacity breaches that do not result in damage to assets;

[34] It should be noted that the two hour emergency rating is not the same on all power transformers on the network. The OEM type test certificates and design specification need to be referred to determine the two hour emergency rating.

- Avoiding supply security breaches;
- Enhancing network efficiency (including works programme synergy); and
- Opportunist implementation of long-term development opportunities (such as installation of cable ducts when other authorities do trenching work and are prepared to accommodate Vector in this).

5.3.6 Demand Management

Vector's load control strategy (see also Section 3.5) aims to offer:

- Network performance improvements by shedding interruptible loads (with customer agreement) in the event of faults. This allows load to be reduced without depriving customers of supply altogether;
- Improved capital efficiency and asset utilisation by reducing network peak demands. This defers the need for capital investment for additional network capacity; and
- Offering tariffs that take advantage of off-peak electricity consumption.

Some of the existing load management assets have been in service since the early 1950's. Progressive changes to the transmission pricing methodology in 2006 has meant that load control to contain GXP demands is no longer the key driver, nor the revenue earner it used to be to support the load control system. At present the system is predominantly used to shed load during contingency situations or where there is a short-term risk that network capacity may be exceeded.

Demand management will have an increasing role in the future, but with increasing application of two way communication, fibre–to-the-home, home management systems, smart appliances, smart meters and smart grids expected to emerge over the medium-term, further investment in conventional load control plants needs to be carefully considered.

5.4 Load Forecasts

Based on the forecasting methodology described earlier, the forecast coincident maximum demand across Vector's network is discussed below.

5.4.1 Forecast new customer connections

As noted above, the dominant drivers for electricity demand in the Auckland region are the number of ICPs on the network and discrete step-changes in large customer demand. The bulk of ICPs are constituted by residential and to a lesser degree commercial customers.

Historical population and ICP growth in Vector's distribution area is indicated in Table 5-4. Over time there has been a small increase in the overall population/ICP ratio, supported by a trend observed in recent years of an increased number of people per ICP.

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Auckland population	1,207,940	1,237,680	1,267,420	1,297,160	1,326,900	1,349,560	1,372,220	1,394,880	1,417,540	1,440,200
ICP's	469,447	476,752	487,991	495,305	504,138	512,436	518,467	523,394	528,417	531,968
Population /ICP ratio (overall)	2.57	2.60	2.60	2.62	2.63	2.63	2.65	2.67	2.68	2.71

Annual population growth	29,740	29,740	29,740	29,740	22,660	22,660	22,660	22,660	22,660
Annual ICP growth	7,305	11,239	7,314	8,833	8,298	6,031	4,927	5,023	3,551
Population/ ICP ratio (new connections)	4.07	2.65	4.07	3.37	2.73	3.76	4.60	4.51	6.38

Note: Population figures for 2007 to 2011 are assumed (by Statistics NZ), not based on an actual census. An allowance has been made to correct for the part of Franklin District that falls outside Vector's distribution area but is normally included in the Auckland population figures.

Table 5-4 : Population and ICP trends in the Vector distribution area

Statistics NZ has projected population growth figures that will see the population of Auckland exceed 2 million people by 2031, which translates to 1.88 million within the Vector distribution area.[35]

Application of the current population/ICP ratio (2.7) to the Statistics NZ population forecast, assuming linear growth, produces an ICP increase of around 8,400 per annum.

However, in recent years – as indicated in Table 5-4 - the actual increase in ICP numbers has been considerably less than this and the ratio of population to ICP has increased to around 6.38 for new connections in the current year.

In Figure 5-5, the uncertainty associated with these forecasts, based on the range of possible ICP ratios is indicated, assuming a constant annual population increase (and using the average connection ratio of the last three years as basis for deriving the lower boundary). Over ten years, the expected outcome can vary by almost 40,000 ICPs.

Accurately forecasting ICP numbers is, therefore, difficult. In addition, conflicting business requirements are based on ICP forecasts:

- ICP forecasts drive Vector's energy and, hence, revenue forecasts. Prudency dictates that these forecasts should be at the conservative (lower) end of the possible ICP range. Over-forecasting will lead to worse than forecast financial performance; and
- From an asset investment perspective, conservative planning would dictate that forecasts at the highest end of the possible range. Under-forecasting will lead to under-investment and security of supply breaches.

To closely reflect the differing growth on the Northern and Southern networks, ICP forecasts have been calculated for each network. The aggregated Vector forecast is shown in Figure 5-5. The supporting ICP numbers are shown in Table 5-5. The process used for deriving these numbers is as follows:

- Upper ICP forecast - using the highest proportion of ICP growth to population growth from the last 5 years for Residential and SME (small to medium enterprise) (calculated separately) added to an average I&C (industrial and commercial) ICP growth from the last 5 years;
- Lower ICP forecast - using the lowest proportion of ICP growth to population growth from the last 5 years for Residential and SME (calculated separately) added to an average I&C ICP growth from the last 5 years;

[35] Part of Franklin District is classified as within the Auckland region but is outside Vector's reticulation area

- 50th percentile – taking the average for the residential and SME growth and adding it to an average I&C ICP growth from the last 5 years; and
- 25th percentile - taking the 25th percentile for the residential and SME growth and adding it to an average I&C ICP growth from the last 5 years.

Essentially, I&C ICPs have been held constant with the Residential and SME growth moving with population. This will mean that the 50th percentile and 25th percentile will be slightly off the average of the upper and lower ICP forecasts.

Taking the above into account, the Vector ICP growth forecast prepared by the Commercial Group – used for connection and revenue planning - has been set at the 25th percentile of the likely ICP growth range.

Conversely, for network planning purposes, ICP growth is assumed to lie at the 50th percentile of the indicative range. While this represents some risk of security level breaches should growth be more rapid than assumed, this is deemed acceptable given the significant degree of redundancy on the network (and hence that a security of supply breach is unlikely to automatically cause an outage). In addition, the asset investment plan is updated on an annual basis, reflecting actual ICP growth in the previous year. At the relatively low ICP growth rate foreseen, the impact of a one-year delay in investment is unlikely to be severe.

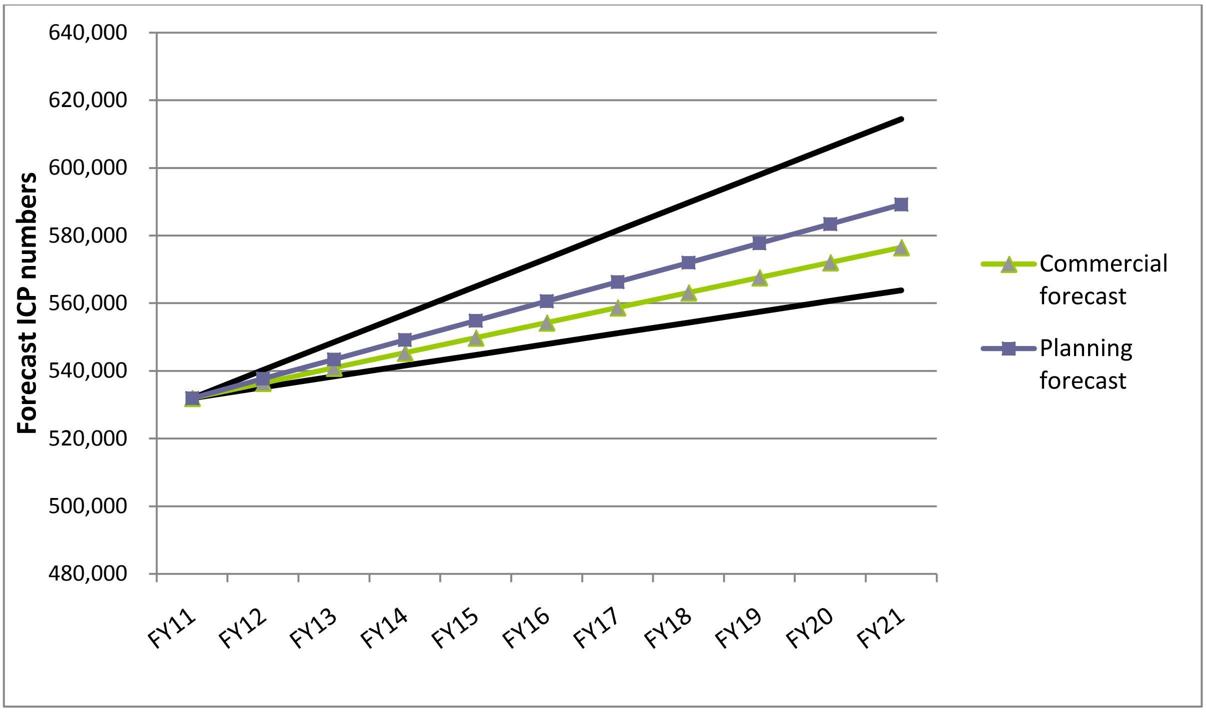


Figure 5-5 : Range of ICP forecasts

In Table 5-5 Vector's ICP forecasts are indicated. Table 5-6 shows the forecast expenditure on connections[36] for the next ten years.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Population forecast	1,440,200	1,462,700	1,485,200	1,507,700	1,530,200	1,552,700	1,575,160	1,597,620	1,620,080	1,642,540	1,665,000
Upper ICP forecast	531,968	540,242	548,516	556,789	565,063	573,337	581,601	589,865	598,129	606,393	614,658

[36] Includes all customer connection capital expenditure plus easement provision

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Asset Investment forecast	531,968	537,701	543,435	549,168	554,901	560,634	566,360	572,085	577,811	583,536	589,262
ICP increase (AI forecast)	3,551	5,733	5,733	5,733	5,733	5,733	5,725	5,725	5,725	5,725	5,725
Commercial forecast	531,968	536,431	540,894	545,357	549,820	554,283	558,739	563,195	567,651	572,107	576,563
ICP Increase (commercial forecast)	3,551	4,463	4,463	4,463	4,463	4,463	4,456	4,456	4,456	4,456	4,456
Lower ICP forecast	531,968	535,161	538,353	541,546	544,739	547,931	551,118	554,305	557,492	560,679	563,865

Table 5-5 : ICP forecasts used by Vector

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Connection budget	$19.2m	$20.2m	$20.7m	$20.8m	$21.1m	$21.1m	$21.2m	$21.2m	$21.2m	$21.2m	$21.2m

Table 5-6 : Forecast customer connection expenditure

5.4.2 Large Customer Expenditure Forecast

Table 5-44 lists the forecast expenditure on projects that are initiated by customers but require significant investments in the network infrastructure to supply the demand requested. These projects have been separately identified from normal network reinforcements due to the uncertainty of timing and scope. The projects in the first five years reflect our best estimate based on information received from the customer (refer Section 5.3.2). Certainty around project timing reduces as we move away from the current year's budget. To recognise the need for large customer projects, a provisional sum of $5m per annum has been included in the capex forecast from 2016 to 2021.

5.4.3 Demand forecasts for the AMP period

The forecast zone substations and bulk in-feed substations demand is provided in Table 5-8 and Table 5-9 for summer and winter peak demand projections respectively. Overall network demand forecast is indicated in Table 5-7. These forecasts are based on the ICP forecasts discussed above, and known large customer changes.

Name	Actual load 2010	Forecast - Summer MVA										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Vector Coincident	1364	1401	1441	1482	1525	1574	1608	1639	1671	1702	1733	1753
Name	**Actual load 2010**	**Forecast - Winter MVA**										
		2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Total Vector Coincident	1741	1779	1807	1837	1867	1903	1935	1969	2001	2032	2062	2083

Table 5-7 : Overall Vector network demand forecast (coincident peak)

Substation	Cyclic Capacity	Actual 2010	Forecast - Summer MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Atkinson Road	24	9.9	10.1	10.4	10.7	11.1	11.4	11.5	11.6	11.7	11.8	11.9	12.0
Auckland Airport	50	17.1	20.9	22.4	23.9	25.4	26.9	28.4	31.1	33.8	35.3	36.8	38.1
Avondale	43.2	16.8	17.2	17.6	18.1	18.5	19.0	19.2	19.3	19.5	19.7	19.9	20.0
Bairds	44	17.1	16.5	16.9	17.3	17.8	18.2	18.5	18.9	19.2	19.5	19.9	20.1
Balmain	12.8	4.8	4.7	4.9	5.1	5.2	5.4	5.5	5.5	5.6	5.6	5.7	5.7
Balmoral	17.4	10.6	10.2	10.4	10.6	10.8	11.1	11.2	11.2	11.3	11.4	11.4	11.5
Belmont	28	7.1	7.0	7.2	7.3	7.5	7.7	7.7	7.8	7.9	7.9	8.0	8.0
Birkdale	30.5	13.8	13.7	14.1	14.6	15.0	15.5	15.6	15.7	15.9	16.0	16.1	16.2
Brickworks	12.8	8.6	8.3	8.5	8.7	8.8	9.0	9.1	9.2	9.3	9.4	9.4	9.5
Browns Bay	28	8.8	8.2	8.5	8.8	9.1	9.5	9.6	9.8	9.9	10.0	10.2	10.3
Bush Road	42.1	25.1	25.4	25.7	26.0	26.3	26.6	26.8	27.0	27.2	27.4	27.5	27.7
Carbine	34.3	25.8	19.0	19.3	19.5	19.7	20.0	20.1	20.3	20.5	20.7	20.8	20.9
Chevalier	20	9.6	8.1	8.4	8.6	8.9	9.1	9.2	9.3	9.4	9.4	9.5	9.6
Clendon	44	4.9	5.1	5.3	5.5	5.7	6.0	6.1	6.3	6.4	6.5	6.7	6.8
Clevedon	5.5	2	2.4	2.5	2.6	2.7	2.9	2.9	3.0	3.0	3.1	3.2	3.2
Coatsville	8.4	5.5	5.5	5.7	5.9	6.1	6.3	6.4	6.5	6.6	6.7	6.8	6.9
Drive	34.1	18.2	16.9	17.3	17.8	18.4	19.1	19.4	19.7	20.0	20.2	20.3	20.4
East Coast Road	23.8	10.8	11.3	11.6	11.9	12.3	12.6	12.8	12.9	13.0	13.2	13.3	13.4
East Tamaki	44	15.3	15.7	15.8	16.0	16.1	16.3	16.5	16.6	16.8	16.9	17.1	17.2
Forrest Hill	35.2	10.1	10.4	10.7	11.1	11.4	11.8	11.9	12.0	12.1	12.2	12.3	12.4
Freemans Bay	38.7	17.1	17.7	18.0	18.4	19.3	20.3	20.5	20.8	21.1	21.4	21.7	21.9
Glen Innes	12	9.4	6.1	6.3	6.9	7.1	7.4	7.5	7.6	7.7	7.8	8.0	8.0
Greenhithe	30	6.2	6.6	7.0	7.4	7.9	8.4	8.6	8.8	9.1	9.4	9.7	9.9
Greenmount	55.7	37.9	38.5	39.5	40.6	41.7	42.8	43.8	44.9	45.9	47.1	48.2	49.2
Gulf Harbour	30	3.8	1.6	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hans	34.4	21.9	21.9	22.5	23.0	23.6	24.1	24.5	24.9	25.3	25.7	26.2	26.5
Hauraki	12.8	5.4	5.6	5.8	5.9	6.0	6.2	6.2	6.3	6.4	6.4	6.5	6.6
Helensville	18	8.3	8.5	8.8	9.1	9.4	9.8	9.9	10.1	10.3	10.4	10.6	10.7
Henderson Valley	28	19.1	19.3	19.7	20.1	20.5	20.9	21.1	21.3	21.6	21.8	22.1	22.2
Highbrook	33.2	4.1	4.2	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.9	5.0
Highbury	15.2	7.8	8.3	8.5	8.7	9.0	9.2	9.3	9.5	9.6	9.7	9.8	9.9
Hillcrest	47.6	17.9	18.7	19.2	19.7	20.2	20.7	20.9	21.2	21.5	21.7	22.0	22.2
Hillsborough	20		13.5	13.9	14.4	14.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4
Hobson 110/11kV	50	28.1	27.9	29.2	29.9	30.5	31.2	31.8	32.4	33.0	33.6	34.2	34.4
Hobson 110kV	130	63.1	63.8	66.7	69.0	71.6	74.7	77.0	79.3	81.2	83.2	85.2	86.2
Hobson 22/11kV	30	15.1	15.4	15.8	16.2	16.7	17.1	17.4	17.8	18.1	18.5	18.9	19.0
Hobson 22kV	80	35.6	36.6	38.2	39.9	41.8	44.3	46.0	47.8	49.1	50.5	51.9	52.7
Hobson 22kV distribution		4.2	4.3	5.1	6.0	6.7	7.8	9.0	10.2	10.9	11.6	12.4	12.9
Hobsonville	32	12.7	12.6	13.0	13.4	13.8	14.3	14.5	14.7	14.9	15.1	15.3	15.4
Hospital	10	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Howick	45.8	21.6	22.1	22.7	23.3	23.9	24.5	24.7	24.9	25.2	25.4	25.6	25.8

Substation	Cyclic Capacity	Actual	Forecast - Summer MVA										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
James Street	32	14.6	14.9	15.3	15.8	16.2	16.6	16.8	16.9	17.0	17.2	17.3	17.4
Keeling Road	24	8.1	7.0	7.2	7.4	7.5	7.7	7.8	7.9	8.0	8.1	8.2	8.2
Kingsland	48	18.0	18.5	18.9	19.3	19.7	20.3	20.5	20.7	21.0	21.3	21.5	21.7
Kingsland 22kV	102.5	36.2	35.3	36.1	36.9	37.9	38.9	39.3	39.7	40.1	40.5	40.9	41.1
Laingholm	16.8	5.8	5.4	5.6	5.7	5.9	6.0	6.1	6.1	6.2	6.2	6.3	6.3
Liverpool	72	49.2	48.9	46.0	46.9	47.8	48.8	49.6	50.4	51.3	52.1	53.0	53.3
Liverpool 22kV	180	104.6	107.0	110.2	112.8	115.3	117.9	120.3	122.7	124.7	126.7	129.0	130.2
Liverpool 22kV distribution		5.9	8.5	13.8	14.7	15.3	16.0	16.9	17.8	18.2	18.6	19.3	19.9
Mangere Central	34.5	19	20.4	21.1	21.8	22.5	23.3	23.9	24.5	25.1	25.8	26.4	27.0
Mangere East	36.4	15.2	16.1	16.6	17.3	17.9	18.6	19.0	19.6	20.1	20.6	21.2	21.7
Mangere West	66	15.7	15.3	15.6	16.0	16.4	16.7	17.0	17.3	17.6	17.9	18.2	18.5
Manly	30.4	10.2	11.8	12.1	12.4	12.8	13.2	13.3	13.4	13.6	13.7	13.8	13.9
Manukau	64.3	24.8	24.3	25.1	25.9	26.7	27.6	28.3	28.9	29.6	30.3	31.1	31.7
Manurewa	47.2	30.5	26.9	27.7	28.5	29.3	30.2	30.7	31.3	31.9	32.4	33.0	33.5
Maraetai	29.6	4.4	4.9	5.3	5.7	6.1	6.5	6.7	6.9	7.1	7.3	7.5	7.7
McKinnon	53.8	20.7	21.8	22.9	24.1	25.5	26.9	27.8	28.9	29.9	31.0	32.2	32.8
Mcleod Road	16	7.9	7.9	8.1	8.3	8.5	8.8	8.9	9.0	9.1	9.2	9.3	9.4
McNab	62.2	37.4	37.7	38.7	39.7	40.3	41.2	42.2	42.9	43.7	44.1	44.5	44.6
Milford	14	5.1	5.6	5.8	6.0	6.2	6.4	6.5	6.6	6.7	6.8	6.9	6.9
Mt Albert	9.8	5.9	6.7	6.8	7.0	7.2	7.3	7.4	7.5	7.6	7.7	7.7	7.8
Mt Wellington	48	22.7	20.6	22.2	23.3	23.8	24.4	24.7	25.1	25.4	25.8	26.2	26.3
New Lynn	30	10.1	10.3	10.6	10.9	11.2	11.5	11.6	11.8	11.9	12.1	12.2	12.3
Newmarket	72	37.2	38.6	40.4	41.3	42.5	44.6	46.6	48.8	51.1	53.4	55.7	57.0
Newton	26.5	17.4	17.2	17.5	18.0	18.4	18.8	19.1	19.4	19.7	20.0	20.3	20.5
Ngataringa Bay	14	7.4	7.1	7.2	7.3	7.4	7.5	7.5	7.5	7.5	7.6	7.6	7.6
Northcote	15.2	4.9	4.4	4.5	4.6	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3
Onehunga	19.7	16.4	12.5	13.2	13.9	14.2	14.5	14.7	14.8	15.0	15.2	15.4	15.5
Orakei	27.4	13.9	11.5	12.1	12.7	13.4	14.2	15.4	15.5	15.6	15.8	15.9	16.0
Oratia	15	3.2	3.3	3.4	3.6	3.7	3.8	3.8	3.9	3.9	3.9	4.0	4.0
Orewa	25.5	8.1	8.4	8.7	9.1	9.4	9.8	9.9	10.1	10.2	10.4	10.6	10.7
Otara	41.7	24.7	24.2	25.7	27.3	29.0	30.8	32.3	33.9	35.6	37.3	39.2	41.0
Pacific Steel	80	52.8	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2	53.2
Pakuranga	39.1	13.2	13.6	14.0	14.3	14.7	15.1	15.2	15.4	15.5	15.7	15.9	16.0
Papakura	35.4	17.4	18.3	18.6	18.9	19.3	19.7	19.8	20.0	20.3	20.5	20.7	20.8
Parnell	10.6	9.0	9.2	9.4	9.6	9.9	10.1	13.3	13.9	14.5	15.1	15.8	15.9
Ponsonby	17.9	9.0	9.3	9.5	9.8	10.0	10.3	10.3	10.4	10.5	10.6	10.6	10.7
Quay	48	22.5	22.0	22.5	23.8	26.0	26.2	25.8	16.1	16.4	16.7	17.0	17.0
Quay 22kV	126	36.6	37.2	38.9	40.6	43.1	43.8	46.7	47.0	48.6	50.3	51.9	52.7
Quay 22kV distribution		5.0	5.9	6.9	7.1	7.3	7.4	7.6	17.0	17.7	18.4	19.1	19.7
Ranui		4	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Red Beach	30	7.4	9.5	9.8	10.1	10.5	10.8	10.9	11.1	11.2	11.3	11.5	11.5

Substation	Cyclic Capacity	Actual 2010	Forecast - Summer MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Remuera	48	17.2	13.9	14.5	15.2	16.2	17.3	18.2	19.2	20.1	21.1	21.7	21.8
Riverhead	18	8.1	8.9	9.3	9.6	10.0	10.4	10.6	10.8	11.0	11.2	11.5	11.6
Rockfield	32.5	15.7	15.1	15.4	15.7	15.9	16.2	17.2	18.6	20.1	21.5	21.7	21.8
Rosebank	37.7	20.3	19.7	22.0	22.3	22.6	22.9	23.1	23.3	23.5	23.6	23.8	23.9
Sabulite Road	25.5	11.4	11.6	12.0	12.4	12.8	13.3	13.5	13.7	13.8	14.0	14.2	14.4
Sandringham	28	13.6	13.8	14.1	14.5	14.8	18.8	18.9	19.0	19.1	19.2	19.3	19.4
Sandringham 22kV	33	23.7	23.6	24.1	24.6	25.2	29.4	29.5	29.7	29.9	30.1	30.3	30.4
Simpson Road	9	4.1	3.1	3.2	3.4	3.5	3.6	3.7	3.7	3.8	3.8	3.9	3.9
Snells Beach	9	4.3	4.3	4.4	4.6	4.8	4.9	5.0	5.1	5.2	5.3	5.3	5.4
South Howick	34.8	16.3	18.3	18.9	19.4	20.1	20.7	21.0	21.3	21.7	22.0	22.4	22.7
Spur Road	14	10.1	10.1	10.5	10.9	11.3	11.8	12.0	12.3	12.6	12.8	13.1	13.3
St Heliers	26.3	11.9	11.8	12.2	12.6	13.0	13.4	13.5	13.6	13.7	13.9	14.0	14.1
St Johns	48		11.1	11.6	12.3	13.0	13.8	14.5	15.1	15.8	16.5	17.1	17.4
St Johns 33kV	62.2	25.4	34.4	35.9	37.6	39.4	41.3	43.3	44.2	45.2	46.1	46.9	47.4
Sunset Road	30	15.6	16.4	16.7	16.9	17.2	17.5	17.6	17.7	17.8	17.9	18.0	18.1
Swanson	15.2	8.2	8.1	8.4	8.7	9.0	9.3	9.5	9.6	9.8	9.9	10.1	10.2
Sylvia Park	36.4	10.4	16.7	16.8	16.9	17.0	18.1	19.1	20.2	21.2	21.8	22.3	22.4
Takanini	29	13.9	14.4	14.8	15.2	15.6	16.0	16.3	16.6	16.9	17.3	17.6	17.9
Takapuna	24	9.6	9.9	10.1	10.2	10.4	10.5	10.7	10.8	11.0	11.1	11.3	11.4
Te Atatu	28	13	10.5	10.9	11.3	11.7	12.1	12.3	12.5	12.7	12.9	13.0	13.1
Te Papapa	39.8	23.0	21.4	21.6	21.8	22.0	22.2	22.4	22.5	22.7	22.9	23.1	23.1
Torbay	12.8	5	5.0	5.2	5.4	5.7	5.9	6.0	6.1	6.1	6.2	6.3	6.4
Triangle Road	24	12.4	10.8	11.2	11.5	11.9	12.3	12.5	12.7	12.9	13.1	13.3	13.4
Victoria	39.2	25.9	26.3	26.8	27.3	27.8	28.3	28.7	29.1	29.5	29.9	30.4	30.5
Waiake	15	5.3	5.7	5.8	6.0	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.8
Waiheke	27.5	6.7	6.7	7.0	7.3	7.6	7.9	8.0	8.1	8.3	8.4	8.6	8.6
Waikaukau	9	4.1	4.3	4.4	4.6	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.3
Waimauku	8.4	4.8	4.6	4.8	5.0	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9
Wairau	32	14.1	14.4	14.6	14.8	15.0	15.2	15.4	15.5	15.6	15.8	15.9	16.0
Wairau 110KV	195	82	83.4	85.4	87.5	89.7	91.9	92.8	93.8	94.8	95.7	96.7	97.3
Warkworth	27	13.4	13.3	13.7	14.1	14.5	14.9	15.2	15.4	15.6	15.8	16.1	16.2
Wellsford	18	6.2	6.4	6.5	6.7	6.8	7.0	7.1	7.2	7.2	7.3	7.4	7.5
Westfield	43.1	30.0	30.1	30.5	30.9	31.4	31.8	32.1	32.4	32.7	33.0	33.4	33.5
White Swan	33.8	18.9	15.5	16.0	16.6	17.1	17.7	17.8	18.0	18.1	18.3	18.4	18.5
Wiri	59.5	40.7	41.5	42.9	44.3	45.7	47.2	48.4	49.7	51.0	52.4	53.8	55.1
Woodford	15.2	9	8.4	8.6	8.8	9.0	9.1	9.3	9.4	9.5	9.6	9.7	9.8

Table 5-8 : Summer peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

		Actual	Forecast - Winter MVA										
Substation	Cyclic Capacity	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Atkinson Road	24	18.2	18.1	18.2	18.3	18.4	18.6	18.7	18.8	18.9	19.0	19.1	19.2
Auckland Airport	50	16.5	18.3	19.7	21.1	22.5	24.0	25.4	28.1	30.8	32.2	33.6	34.9
Avondale	48	27.4	27.7	27.9	28.2	28.4	28.6	28.8	29.0	29.2	29.4	29.6	29.7
Bairds	48	22.6	22.9	23.3	23.7	24.1	24.5	24.8	25.2	25.6	25.9	26.3	26.6
Balmain	12.8	8.7	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.8	8.9	9.0	9.0
Balmoral	26.4	15	15.4	15.6	15.7	15.8	15.9	16.0	16.1	16.1	16.2	16.3	16.4
Belmont	28	13	13.9	14.0	14.1	14.2	14.3	14.3	14.4	14.5	14.6	14.7	14.8
Birkdale	30.5	22.3	23.1	23.3	23.4	23.6	23.7	23.9	24.0	24.2	24.4	24.5	24.6
Brickworks	12.8	7.3	8.3	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.8	8.9	9.0
Browns Bay	28	14.9	14.2	14.4	14.6	14.8	15.0	15.2	15.4	15.5	15.7	15.9	16.1
Bush Road	42.1	24.9	25.1	25.3	25.5	25.7	25.9	26.0	26.2	26.4	26.6	26.8	26.9
Carbine	41.7	24.2	18.1	18.3	18.5	18.7	18.9	19.0	19.2	19.3	19.5	19.7	19.8
Chevalier	20	17.6	15.2	15.2	15.3	15.4	15.5	15.6	15.7	15.8	15.9	16.0	16.0
Clendon	48	15.4	15.7	16.1	16.5	16.8	17.2	17.6	17.9	18.3	18.7	19.1	19.4
Clevedon	6	3.5	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.9	4.9	5.0	5.1
Coatsville	11.5	9.5	9.6	9.7	9.8	9.9	10.1	10.2	10.3	10.4	10.5	10.7	10.8
Drive	48	29.9	26.4	26.6	26.7	27.1	27.6	28.0	28.4	28.8	29.0	29.1	29.3
East Coast Road	23.8	16.5	17.2	17.3	17.4	17.6	17.7	17.9	18.0	18.1	18.3	18.4	18.5
East Tamaki	48	16.1	15.7	15.8	16.0	16.1	16.3	16.4	16.6	16.8	17.0	17.1	17.3
Forrest Hill	45.2	16.6	16.7	16.8	16.9	17.0	17.2	17.3	17.4	17.5	17.6	17.8	17.9
Freemans Bay	45.6	17.9	18.1	18.4	18.7	19.4	20.1	20.4	20.6	20.9	21.2	21.4	21.6
Glen Innes	21.8	13.6	9.6	9.7	10.3	10.4	10.6	10.8	10.9	11.1	11.2	11.4	11.5
Greenhithe	30	12.4	12.8	13.2	13.6	14.1	14.5	14.9	15.3	15.7	16.1	16.5	16.9
Greenmount	72	38.2	38.1	39.0	39.9	40.8	41.7	42.6	43.5	44.5	45.5	46.5	47.4
Gulf Harbour	30	6.9	6.9	7.0	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6	7.7
Hans	44.7	23.9	24.7	25.1	25.5	25.9	26.3	26.7	27.1	27.5	28.0	28.4	28.7
Hauraki	12.8	8.1	8.4	8.5	8.6	8.7	8.8	8.8	8.9	9.0	9.1	9.2	9.3
Helensville	18	13.2	13.1	13.3	13.5	13.7	14.0	14.2	14.4	14.6	14.8	15.0	15.2
Henderson Valley	28	22.8	22.2	22.5	22.7	23.0	23.2	23.5	23.7	24.0	24.2	24.5	24.7
Highbrook	40.8	4.5	4.6	4.7	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5
Highbury	15.2	10.7	11.1	11.2	11.4	11.5	11.6	11.8	11.9	12.0	12.1	12.3	12.4
Hillcrest	47.6	23.4	24.4	24.7	25.0	25.3	25.6	25.9	26.2	26.5	26.8	27.1	27.3
Hillsborough	20		17.9	18.1	18.2	18.4	18.6	18.7	18.9	19.1	19.2	19.4	19.6
Hobson 110/11kV	50	26.7	26.4	27.6	28.2	28.8	29.4	30.0	30.5	31.1	31.6	32.2	32.4
Hobson 110kV	130	63.5	63.9	66.5	68.5	70.8	73.5	75.7	77.9	79.7	81.5	83.4	84.3
Hobson 22/11kV	30	14.1	14.5	14.8	15.2	15.5	15.9	16.2	16.6	16.9	17.2	17.6	17.7
Hobson 22kV	80	36.9	37.7	39.0	40.4	42.1	44.2	45.9	47.5	48.7	50.0	51.3	52.0
Hobson 22kV distribution		5.4	5.5	6.3	7.1	7.7	8.8	9.9	10.9	11.6	12.2	12.9	13.4
Hobsonville	32	18.6	19.6	19.9	20.1	20.4	20.8	21.0	21.3	21.5	21.8	22.0	22.2
Hospital	15	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Howick	67	37.2	38.5	38.7	38.8	39.0	39.2	39.3	39.4	39.6	39.7	39.8	39.9

Substation	Cyclic Capacity	Actual 2010	Forecast - Winter MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
James Street	32	19.2	19.4	19.5	19.7	19.8	20.0	20.1	20.2	20.4	20.5	20.7	20.8
Keeling Road	24	9.7	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9
Kingsland	48	22.7	23.6	23.8	24.1	24.6	25.1	25.3	25.6	25.9	26.2	26.4	26.6
Kingsland 22kV	144	54	52.9	53.4	53.9	54.5	55.1	55.6	56.0	56.5	56.9	57.3	57.7
Laingholm	16.8	8.7	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.4	9.4	9.4
Liverpool	60	44.3	45.8	42.9	43.7	44.5	45.4	46.2	46.9	47.7	48.5	48.8	49.0
Liverpool 22kV	180	104.6	104.4	107.3	109.8	112.0	114.3	116.6	118.9	120.8	122.7	124.4	125.5
Liverpool 22kV distribution		7	8.1	13.2	14.0	14.7	15.3	16.2	17.0	17.4	17.8	18.5	19.0
Mangere Central	48	24.5	25.1	25.6	26.2	26.7	27.2	27.8	28.3	28.9	29.4	30.0	30.6
Mangere East	48	25.7	23.8	24.3	24.8	25.3	25.8	26.3	26.8	27.3	27.8	28.4	28.9
Mangere West	72	16.4	17.7	18.1	18.5	18.9	19.3	19.6	20.0	20.3	20.7	21.0	21.3
Manly	30.4	14.6	14.8	14.9	15.1	15.2	15.3	15.4	15.6	15.7	15.8	15.9	16.0
Manukau	72	28.9	28.2	28.8	29.5	30.2	30.9	31.6	32.2	32.9	33.6	34.3	35.0
Manurewa	69.8	50.2	50.9	51.6	52.2	52.8	53.5	54.1	54.7	55.3	56.0	56.6	57.2
Maraetai	36	6.7	5.1	5.3	5.5	5.7	6.0	6.1	6.3	6.5	6.7	6.9	7.0
McKinnon	53.8	17.1	18.0	18.7	19.4	20.2	21.0	21.7	22.5	23.2	24.0	24.8	25.3
Mcleod Road	16	12.2	12.0	12.1	12.3	12.4	12.5	12.7	12.8	12.9	13.1	13.2	13.3
McNab	72	43.1	43.7	44.5	45.3	45.7	46.6	47.4	48.2	49.0	49.4	49.8	50.0
Milford	14	8.8	9.0	9.1	9.2	9.4	9.5	9.6	9.7	9.9	10.0	10.1	10.2
Mt Albert	12	9.5	10.5	10.6	10.7	10.8	11.0	11.1	11.2	11.3	11.4	11.5	11.6
Mt Wellington	48	23	20.9	22.1	22.8	23.1	23.5	23.8	24.1	24.4	24.7	25.0	25.2
New Lynn	30	14.9	14.8	15.0	15.2	15.4	15.5	15.7	15.9	16.1	16.2	16.4	16.5
Newmarket	72	36.3	37.0	38.4	38.9	40.4	42.3	44.2	46.2	48.1	50.1	52.1	53.4
Newton	37.3	18.7	18.5	18.8	19.1	19.4	19.8	20.1	20.4	20.7	21.0	21.3	21.5
Ngataringa Bay	14	8.5	8.2	8.3	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.5
Northcote	15.2	8.5	8.5	8.6	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.3	9.3
Onehunga	28.6	20	12.2	12.8	13.3	13.5	13.7	13.8	14.0	14.1	14.3	14.5	14.6
Orakei	40.6	24.2	19.2	19.6	20.2	20.8	21.4	21.8	21.9	22.1	22.3	22.4	22.5
Oratia	15	5.2	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.8
Orewa	30.4	13.7	14.0	14.2	14.5	14.7	15.0	15.2	15.4	15.6	15.8	16.0	16.2
Otara	46.2	30.4	29.8	29.8	31.4	33.0	34.8	36.4	38.2	40.1	42.1	44.2	46.2
Pacific Steel	80	54.9	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7	65.7
Pakuranga	48	23.6	23.2	23.3	23.4	23.6	23.7	23.8	23.9	24.0	24.1	24.2	24.3
Papakura	48	23.1	24.2	24.3	24.4	24.5	24.6	24.8	24.9	25.0	25.1	25.2	25.2
Parnell	12	9.7	9.9	10.0	10.2	10.3	10.4	14.1	14.7	15.3	15.9	16.5	16.6
Ponsonby	26.6	15.4	15.9	16.0	16.1	16.2	16.3	16.4	16.5	16.6	16.7	16.8	16.9
Quay	48	21.1	20.4	20.9	22.1	24.1	24.6	23.3	15.1	15.3	15.6	15.9	15.9
Quay 22kV	126	34	34.2	35.7	37.1	39.3	40.0	42.4	44.4	45.9	47.4	49.0	49.7
Quay 22kV distribution		5.2	5.9	6.9	7.1	7.2	7.4	7.6	17.3	18.0	18.8	19.5	20.1
Ranui		5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Red Beach	30	12.3	12.7	12.8	12.9	13.0	13.2	13.3	13.4	13.5	13.6	13.8	13.9

Substation	Cyclic Capacity	Actual 2010	Forecast - Winter MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Remuera	48	30.6	23.7	24.3	24.9	25.9	27.0	28.1	29.1	30.2	31.3	32.0	32.6
Riverhead	18	9.6	9.8	10.0	10.2	10.4	10.7	10.9	11.1	11.3	11.5	11.7	11.9
Rockfield	48	18.3	17.6	17.7	17.8	18.0	18.1	19.5	20.8	22.2	23.7	23.8	23.9
Rosebank	51.6	22.1	21.4	23.5	23.7	23.9	24.0	24.2	24.4	24.6	24.7	24.9	25.1
Sabulite Road	25.5	18.6	18.6	18.8	19.1	19.3	19.6	19.8	20.1	20.3	20.5	20.8	21.0
Sandringham	43.7	20.5	20.8	21.0	21.1	21.2	25.2	25.3	25.4	25.5	25.6	25.8	25.9
Sandringham 22kV	53.6	35.7	36.4	36.6	36.9	37.1	41.2	41.4	41.6	41.8	42.0	42.2	42.4
Simpson Road	9	7.1	5.7	5.8	5.9	5.9	6.0	6.1	6.1	6.2	6.2	6.3	6.4
Snells Beach	9	6	6.0	6.1	6.1	6.2	6.3	6.4	6.5	6.6	6.6	6.7	6.8
South Howick	48	29.5	30.6	30.9	31.2	31.5	31.9	32.2	32.5	32.8	33.1	33.4	33.7
Spur Road	14	11	10.3	10.5	10.8	11.0	11.3	11.5	11.7	12.0	12.2	12.4	12.6
St Heliers	41.7	22.3	22.5	22.6	22.8	23.0	23.1	23.3	23.4	23.6	23.7	23.9	24.0
St Johns	48		12.5	12.7	13.1	13.5	14.0	14.7	15.3	16.0	16.7	17.4	17.8
St Johns 33kV	96.9	45.5	53.1	53.8	55.0	56.1	57.3	58.5	59.4	60.4	61.4	62.4	63.0
Sunset Road	30	18.2	17.7	17.8	17.9	18.1	18.2	18.3	18.4	18.5	18.6	18.7	18.8
Swanson	15.2	13.6	12.3	12.5	12.7	12.9	13.1	13.2	13.4	13.6	13.7	13.9	14.1
Sylvia Park	48	11	17.2	17.3	17.5	17.6	18.7	19.7	20.8	21.8	22.4	23.0	23.1
Takanini	36	18.2	19.3	19.6	20.0	20.4	20.7	21.1	21.4	21.8	22.2	22.5	22.9
Takapuna	24	9	9.2	9.3	9.5	9.6	9.7	9.9	10.0	10.1	10.3	10.4	10.5
Te Atatu	28	19.9	20.8	21.0	21.3	21.6	21.9	22.1	22.4	22.7	23.0	23.3	23.4
Te Papapa	48	23	22.2	22.4	22.6	22.8	23.0	23.2	23.3	23.5	23.7	23.9	24.0
Torbay	12.8	9.8	10.1	10.2	10.4	10.5	10.7	10.8	10.9	11.0	11.2	11.3	11.4
Triangle Road	24	19.4	17.3	17.6	17.8	18.1	18.4	18.7	18.9	19.2	19.4	19.7	19.9
Victoria	46.5	24.2	24.6	25.0	25.4	25.8	26.2	26.6	27.0	27.4	27.8	28.2	28.3
Waiake	15	9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5
Waiheke	30	9.3	9.6	9.7	9.9	10.1	10.2	10.4	10.5	10.7	10.9	11.0	11.0
Waikaukau	9	6.8	6.9	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6	7.7
Waimauku	8.4	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.1	7.2	7.3	7.4	7.5
Wairau	32	15.9	14.7	14.8	14.9	15.0	15.2	15.3	15.4	15.6	15.7	15.9	16.0
Wairau 110KV	195	130	131.8	133.1	134.3	135.6	136.9	138.1	139.4	140.7	142.0	143.3	144.1
Warkworth	27	16.8	17.3	17.6	17.8	18.1	18.4	18.6	18.8	19.1	19.4	19.6	19.8
Wellsford	18	7.3	7.4	7.5	7.5	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.3
Westfield	60	31	31.4	31.7	32.1	32.5	32.9	33.2	33.5	33.9	34.2	34.5	34.7
White Swan	48.9	30.6	24.1	24.3	24.4	24.6	24.8	24.9	25.1	25.2	25.4	25.6	25.7
Wiri	72	34	35.5	36.4	37.5	38.5	39.6	40.6	41.6	42.6	43.7	44.8	45.8
Woodford	15.2	10.4	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	10.0

Table 5-9 : Winter peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

5.5 Non-network and Non-capacity Options

Vector is continually considering alternatives to investing in network solutions to meet customers' capacity and security requirements. Alternative solutions include non-network solutions or non-capacity network solutions.

Non-capacity solutions refer to those network solutions that do not involve investment in major network assets such as lines, cables or transformers.

Non-network solutions refer to demand side solutions independent of the Vector network. However, with the exception of embedded generation, non-network opportunities investigated to date have generally not been economically viable or sufficiently technically robust.

Some non-network solutions are being considered or trialled and other developments are being monitored with a view to being an early adopter (rather than first mover) of new technology once international evidence indicates that the technology is viable and reliable. Solutions adopted to avoid major network investment are being monitored and are described in the paragraphs below.

5.5.1 Load Shifting (Non-capacity)

This option allows the transfer of load between adjacent zone substations by moving distribution feeder open points to optimise network performance (utilise diversity to reduce overall demand, improve voltage, reduce losses, enhance security and reliability etc) or minimise the time to carry out manual field switching in the event of a fault. This activity is generally carried out following a load flow study to understand the consequences of the action. Maintaining sufficient backstop capability to supply customers in accordance with security standards and contracted service levels is the key consideration for this option.

5.5.2 Load Shedding (Non-capacity)

Vector's security standard allows zone substations to be loaded above their firm capacity for a percentage of the time, to maintain load while reconfiguring the network following a fault. To ensure assets are not damaged by overloading in the process, emergency load shedding schemes have been developed to shed load automatically. Load is restored via the SCADA when demand reduces to within equipment capacity.

5.5.3 Renewable Solutions (Non-network)

PV panels, wind driven micro turbines and solar water heating all offer the potential for customers to reduce energy purchases from the grid. Currently PV panels are too expensive for widespread uptake for residential applications but the cost of these panels is reducing rapidly. Solar water heating is another means of utilising natural resources to reduce energy supplied from the network, but compared to PV it is not as versatile and this is expected to limit its development. Micro wind turbines have not yet proved economically viable.

These solutions will likely contribute to a reduction in overall energy consumption but will not always reduce peak demands. An energy storage system (such as rechargeable batteries) will help to utilise the renewable energy to reduce peak demand, but they are not yet economically viable. The development of these technologies is being closely monitored.

5.5.4 Interruptible Load (Non-capacity)

An ability to interrupt customer demand during network contingencies or peak demand periods will enable Vector to avoid significant network reinforcements. Viable commercial arrangements are required to encourage customers to offer their load for shedding. An alternative is to invite load aggregators to offer "shedable" customer load and make it available at times when the network capacity is constrained. Aggregation is carried out by third parties who would contract with Vector to guarantee a minimum quantity of shedable load.

Vector is exploring options with individual customers and aggregators to develop viable interruptible load models.

5.5.5 Smart Metering (Non-network)

Programmes have started to replace the largely mechanical residential electricity meters with electronic "smart" units. This is being rolled out over the next few years. Current smart metering technology allows two way communications between the meter and the meter owner, which gives huge potential for improving meter reading accuracy and frequency, a better understanding of load patterns, time-of-use tariffs, outage notification etc.

These meters can also offer opportunities for demand side management. Not only can load control signals be issued to domestic appliances (including hot water cylinders presently controlled through load control systems), but customers can also be provided with a continuous indication of their energy usage. The latter, combined with tariff structures that encourage off-peak consumption, can lead to a win-win situation for consumers and distribution utilities – lower energy costs and better load factors.

Full realisation of these benefits is still some way off, but Vector is developing trials to assess what potential exists and will also work with retailers on developing more effective tariff structures.

5.5.6 Smart Technologies (Non-network)

Investigations on a number of technologies such as smart appliances, home energy management systems and smart grids are ongoing to identify how we can use these technologies to help manage peak demands on the network. (See Section 3 for a more in-depth discussion.)

5.5.7 Embedded Generation (Non-network)

Embedded generation refers to those generation connected to the Vector network either directly or via a customer's installation and are capable of exporting electricity into the network. Local generation is generally installed to provide a higher level of security than that offered by the network. The generation capacity is usually less than the customer's demand and is designed to support critical loads until the mains supply is restored.

Since the primary energy source for these units is generally diesel, they are expensive to run and widespread application is, therefore, unlikely. Opportunities do, however, exist where they offer an economically viable solution to improving the security standard of a wider area. Vector has developed standards to facilitate these types of connection and has a team of staff to handle customer connection requests.

5.5.7.1 Embedded generation connection policy

To facilitate connection of embedded generation, Vector has posted its embedded generation connection procedures on its website. The procedures are based on the requirements contained in the regulations. The website also contains information to help the customer to understand the requirements for connection.

Vector's policy for connection of embedded generation to its network includes:

- The presence of embedded generation must not restrict Vector's switching operations on the network;
- Metering equipment installed at embedded generating stations must comply with the requirements of the Electricity Industry Participation Code;
- Embedded generation connected to the Vector network must comply with the requirements of all relevant Regulations and Electrical Codes of Practice, and the relevant requirements specified in the Electricity Industry Participation Code;
- Installation and operation of embedded generation equipment must comply with Vector's Distribution Code; and
- Installation and operation of embedded generation equipment must comply with all requirements as specified in Vector's "Technical Requirements for Connection of Distributed Generation".

5.5.8 Mobile Generator Connecting Unit (Non-network)

As an alternative to large network investment, or to defer large network investments, Vector considers the use of generation to make up the security shortfall and has applied this in the past. Modular generation of 200kVA - 1MVA generator capacity are generally sized for ease of transportation and have the capability to connect onto the LV network. The motor/generator fits into a 20ft container, making transport to site easy. These units are ideal to support load during LV network faults, while repairs are made to the network.

Vector has developed two mobile generator connection units (MGCUs) each capable of connecting up to 2.5MW of generation for feeding into the 11kV network during emergencies. This helps to enhance the security and reliability of the network in areas where security is below N-1. Significant standby and fuelling costs are, however, currently preventing these generators from being widely used.

5.5.9 Energy Substitution (Non-network)

Energy substitution is the option to transfer consumption of one energy source to another. Examples include using reticulated gas or LPG instead of electricity for cooking and water or space heating. While the commercial and industrial sectors are receptive to multi-fuel options particularly where financial benefits result, the residential sector is less enthusiastic to change, largely due to the initial investment required. More detailed investigations are required, including the option of providing customer incentives to switch, before it can be confirmed that energy substitution is an economically viable option to network infrastructure investment.

5.5.10 Voltage Regulator/Capacitors (Non-capacity)

Capacitors are installed on the network as a means of injecting reactive power to improve the network power factor and mitigate excess voltage drop. Traditional approaches rely on banks of capacitors switched into the network as the voltage drops outside preset limits. Technology advancements with fast switching power electronics has resulted in the development of static VAR[37] compensators (SVC), static compensators (STATCOM) and more recently dynamic VAR compensators (D-VAR) as refinements on capacitor banks.

[37] VAR is volt ampere reactive

Voltage regulators are used to boost the voltage on distribution circuits and are generally used in conjunction with capacitor banks. Their key application is on long distribution lines where significant LV problems are experienced. Capacitors and voltage regulators are effective means of solving LV problems in remote areas. If the voltage problem is caused by excessive loading, other solutions such as increasing the size of conductors need to be carefully considered.

Vector has a number of capacitors and voltage regulators in use on its network and will continue to use them in appropriate situations. For example, the plans being finalised to install a second voltage regulator and capacitor bank on the Piha line to mitigate potential LV problems. This approach will defer the construction of a second 5km circuit to partially offload the existing lines.

5.5.11 Remote Area Power System (Non-network)

Electricity supply to remote areas with very low load densities using a conventional network approach is very expensive. Alternatives such as local generation with a combination of diesel, mini hydro, renewable generation, PV, micro wind, batteries, bottled gas, etc could be a more economically attractive alternative.

The application of these alternative technologies is very dependent on the specific circumstance and needs to be assessed on a case-by-case basis.

5.5.12 Automatic Load Transfer Schemes (Non-capacity)

By making use of the different load profiles (residential/industrial) of neighbouring substations, Vector has been able to develop an automatic load transfer scheme to transfer load from a substation to another (of different load characteristics) with only a small increase in the demand of the recipient substation. The automation also enables the load transfer to take place within a fraction of a minute allowing the operators to utilise the short-term (higher) ratings of the assets. The automatic load transfer scheme applied to the Onehunga area enabled deferment of Hillsborough substation by seven years.

Suitable other areas for similar load transfer are being investigated on an ongoing basis to:

- Remove capacity constraints caused by asset components to improve the overall capacity of an asset;
- Explore integrated solutions with customers. Sometimes their initial requirements can be relaxed without any major compromise. This can lead to substantial cost savings;
- Develop short-term solutions that will migrate to a longer term solutions without asset stranding; and
- Leverage off other projects to gain synergies eg. asset replacement, undergrounding, road re-alignment or new road construction activities.

5.6 Network Development Programme

The network development plan for the planning period is discussed in the following sections. Given the accuracy of information available and advanced planning concluded, planning for the first 12 months is at the most detailed level. The plan for the next four years (2013-2016) is somewhat less detailed, while the plans for the remaining five years is at a high level only.

The development projects are discussed per GXP or per sub-transmission network. Only major projects are separately discussed – those with an estimated value of more than $1,000,000.

5.7 Auckland Bulk Supply Development Plan

5.7.1 Transmission Overview

Vector takes supply from Transpower at twelve GXPs to supply its sub-transmission networks in Auckland. A thirteenth GXP exists in Tokoroa to the Fonterra factory (Lichfield). Auckland also has five bulk supply substations as part of its sub-transmission network to supply the various metropolitan population and business centres. The electricity supply into Auckland from generation in the central North Island and the South Island is provided by six 220kV circuits and two 110kV circuits. All eight circuits terminate onto the 220kV bus and 110kV bus at Otahuhu GXP. Two major generating stations exist in Auckland, namely Southdown and Otahuhu. No significant operative generation exists north of Auckland.

Transmission into Auckland, existing GXPs, and the cross-isthmus 220kV (NAaN) cable that will supply two new GXPs at Hobson and Wairau substations, are shown in the geo-schematic Figure 5-6 below.

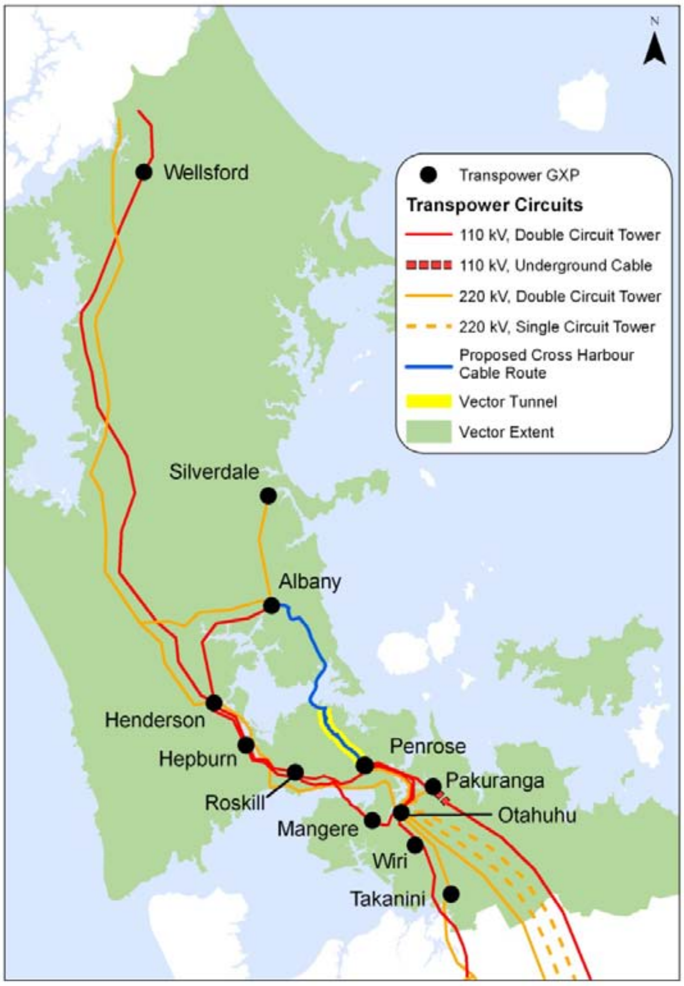


Figure 5-6: Transmission into Auckland and GXPs in Auckland

Recognising the demand growth in the region, Transpower is undertaking major reinforcements of the grid to Northern Auckland and Northland. The North Island grid upgrade project (NIGUP) and North Auckland and Northland (NAaN) projects were approved by the Electricity Commission and are currently in progress. The NIGUP project involves constructing two 400kV rated circuits from Whakamaru to a terminal station at Whitford (Brownhill Rd transition station), in South Auckland. From there two 220kV circuits will run to Pakuranga substation. The 400kV circuit will initially operate at 220kV, and will be uprated to 400kV when warranted by the demand. This project is scheduled for commissioning in 2012.

The NAaN project comprises a single 220kV XLPE cable circuit between Transpower's Pakuranga substation to Penrose and then Albany 220kV substations. Two new GXPs for the Vector network will be leveraged off the NAaN circuit to cost effectively maintain security of supply standards and allow for load growth in the long-term in Auckland's CBD (Hobson) and on Auckland's North Shore (Wairau).

Over the long-term the NAaN project also allows for a 2nd 220kV cable to be installed between Penrose and Albany. The Wairau GXP is scheduled for completion in 2013 and the Hobson GXP in 2014. Figure 5-7[38] shows the NIGUP and NAaN projects (in red).

[38] Figure taken from the Transpower 2010 annual plan and used with the permission of Transpower

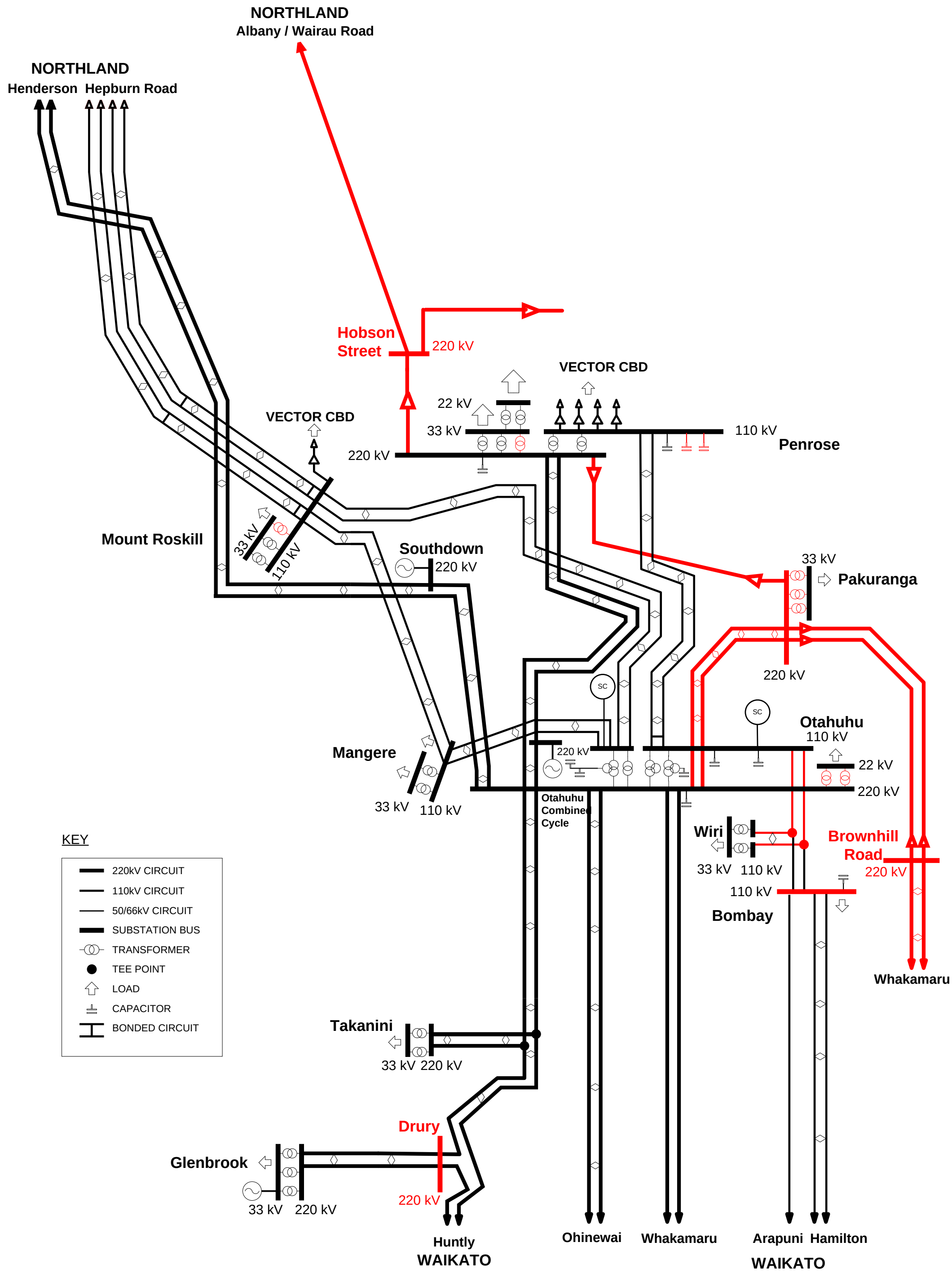


Figure 5-7: Auckland Transmission: NIGUP and NAaN circuits

5.7.2 Grid Exit Points

Table 5-10 and Table 5-11 show the winter and summer peak demands at GXPs and the installed and firm capacity at each of these supply points.

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity[39] (MVA)	2010 Winter Peak Demand (MVA)
Mangere	110kV			55
Mangere	33kV	2x120	118	95
Otahuhu	22kV	2x50	59	56
Pakuranga	33kV	2x120	136	130
Penrose	110kV			191
Penrose[40]	33kV	2x160 + 1x200	428	315
Penrose	22kV	3x45	90	56
Roskill	110kV			54
Roskill	22kV	2x70 + 1x50	141	104
Takanini	33kV	2x150	123	113
Wiri	33kV	2x100	107	75
Albany	110kV			130
Albany	33kV	1x120 + 2x100	234	151
Henderson	33kV	2x120	135	95
Hepburn	33kV	1x85 + 2x120	245	117
Silverdale	33kV	1x120 + 1x100	109	71
Wellsford	33kV	2x30	31	30[41]
Lichfield	110kV			8

Table 5-10 : Grid Exit points - winter loads

[39] Firm capacities (n-1) taken from Transpower planning report.

[40] Penrose 33kV bus supplies Penrose 22kV load.

[41] The Wellsford transformer capacity is presently limited by Transpower's protection equipment. Once this limit is resolved the n-1 capacity will be 37/39MVA (summer/winter).

Grid Exit Point	Supply Voltage	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)	2010 Summer Peak Demand (MVA)
Mangere	110kV			53
Mangere	33kV	2x120	118	84
Otahuhu	22kV	2x50	59	47
Pakuranga	33kV	2x120	136	104
Penrose	110kV			216
Penrose	33kV	2x160 + 1x200	406	275
Penrose	22kV	3x45	90	53
Roskill	110kV			36
Roskill	22kV	2x70 + 1x50	141	65
Takanini	33kV	2x150	123	87
Wiri	33kV	2x100	107	72
Albany	110kV			82
Albany	33kV	3x120 + 2x100	234	109
Henderson	33kV	2x120	135	76
Hepburn	33kV	1x85 + 2x120	239	87
Silverdale	33kV	1x120 + 1x100	109	46
Wellsford	33kV	2x30	31	21
Lichfield	110kV			8

Table 5-11 : Grid Exit points - summer loads

The supply areas of GXPs in the Northern network are shown in Figure 5-8 and that of the Southern in Figure 5-9.

Figure 5-8: GXP distribution zones in the Northern region

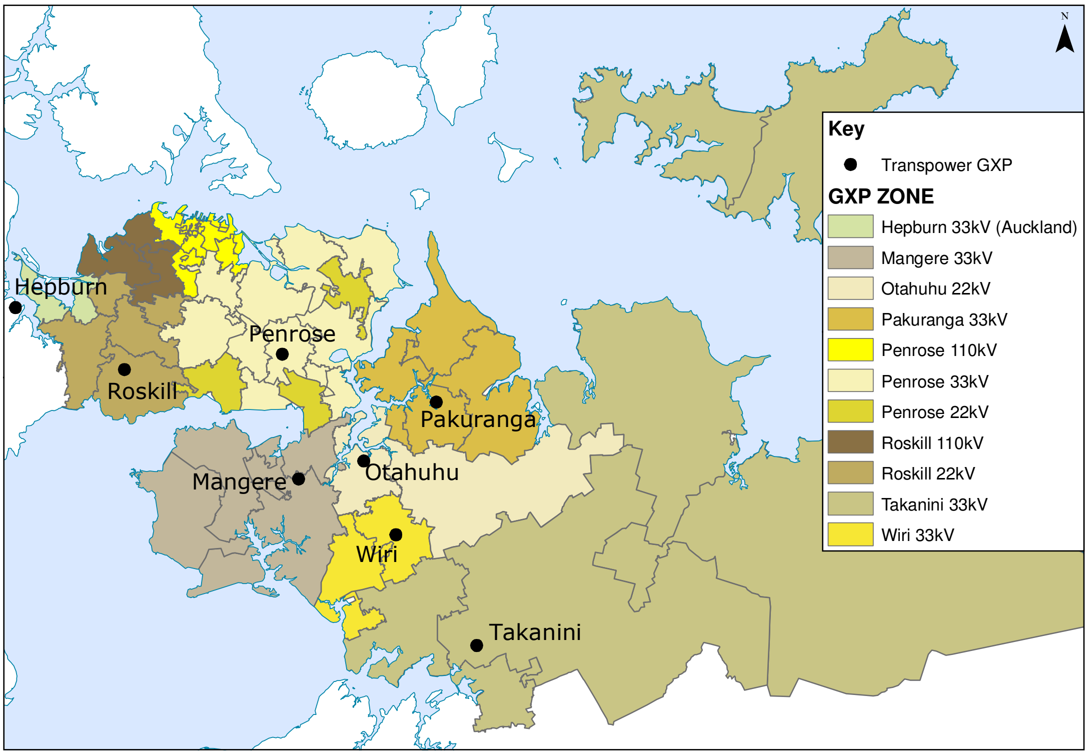


Figure 5-9: GXP distribution zones in the Southern region

5.7.3 Vector-owned Bulk Supply Points

Vector also has five bulk supply substations (110kV) to supply its sub-transmission networks in Auckland and two customer dedicated 110kV supplies (Pacific Steel and Lichfield). These bulk supply substations, listed in Table 5-12 and Table 5-13, are connected to the grid but are some distance away. Both Hobson and Wairau bulk supply points will be upgraded to GXPs by 2014. These projects are stated in more detail further on in this section.

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	N-1 Capacity (MVA)	2010 Winter Peak Demand (MVA)
Kingsland	22kV	2x60	60	55.5
Liverpool	22kV	2x75+1x60	135	104.6
Quay	22kV	1x60+2x50	60	34
Hobson	22kV	2x40	40	36.9
Wairau Road	33kV	3x80	160	130
Pacific Steel	33kV	70+40	40	54.9[42]
Lichfield	11kV	2x20	24	8.5

Table 5-12 : Internal Vector bulk supply points - winter demand

[42] The peak demand is somewhat higher than the firm (n-1) capacity but this scenario is acceptable to the customer and is covered in an agreement with the customer.

Bulk Supply Substation	Supply Voltage	Transformer Installed capacity (MVA)	N-1 Capacity (MVA)	2010 Summer Peak Demand (MVA)
Kingsland	22kV	2x60	60	36.2
Liverpool	22kV	2x75+1x60	135	104.6
Quay	22kV	1x60+2x50	60	36.6
Hobson	22kV	2x40	40	35.6
Wairau Road	33kV	3x80	160	82
Pacific Steel	33kV	70+40	40	52.8
Lichfield	11kV	2x20	24	8.4

Table 5-13 : Internal Vector bulk supply points - summer demand

5.8 Sub-Transmission – Northern

5.8.1 Northern sub-transmission and bulk supply - background

The Northern network has five GXPs, viz: Wellsford, Silverdale, Albany, Henderson and Hepburn and one bulk supply point, namely Wairau Road substation.

5.8.2 Northern sub-transmission and bulk supply – development strategy

Leveraging off the NAaN 220kV circuit being constructed by Transpower, the security of supply to Wairau Rd will be enhanced by connecting the Hobson/Albany 220kV circuit to this site, creating a new GXP. This will address an existing HILP risk around the impact of a pole failure on the double circuit 110kV line currently feeding Wairau substation. Construction work will commence in 2011 with a scheduled commissioning date of June 2013. In preparation for the establishment of the GXP at Wairau, the existing three 110kV Vector OH circuits will be relocated from the vacant land in the designated substation area to provide a clear and safe area for construction of the Transpower facilities. In future, Wairau will be able to be supplied from either Penrose or Albany.

No further new GXPs are planned in the Northern area for the planning period.

5.8.3 Northern sub-transmission and bulk supply – projects

a. Projects – next five years

Wairau substation	Establish a 120MVA 220/33kV GXP in conjunction with Transpower and installation of a new indoor 33kV switchboard to replace the existing outdoor 33kV switchboard
Wellsford substation	Upgrade the protection equipment of the transformers to increase the n-1 capacity to 37/39MVA (summer/winter)

b. Projects – next five to ten years

Silverdale	Alleviate transformer bay constraint
Henderson	Alleviate transformer bay constraint

c. Projects – long-term

Albany 33kV	Alleviate transformer bay constraint
Silverdale	Replace 100MVA transformer
Rodney	Establish a new GXP
Huapai	Establish a new GXP
Henderson	Install a third 11/33kV transformer
Wellsford	Replace the existing two 110/33kV transformers

5.9 Sub-Transmission - Auckland CBD

5.9.1 CBD sub-transmission and bulk supply - background

At present, Auckland CBD has three bulk supply substations, viz. Hobson, Liverpool and Quay substations, all fed with Vector-owned 110kV cables.

The bulk supply to Liverpool substation is from Transpower's Penrose GXP by means of two 237MVA, 110kV XLPE cable circuits in Vector's Penrose tunnel to 110kV GIS switchgear in Liverpool. Three 110/22kV transformers (2 x 75MVA and 1 x 60MVA), supply a 22kV switchboard at Liverpool. Three 22/11kV transformers are connected to the 22kV bus to supply an 11kV bus at Liverpool. Furthermore two 22kV substations, Victoria and Newton, are supplied from the 22kV switchboard at Liverpool.

The bulk supply to Hobson substation is from Vector's 110kV switchgear in Liverpool by means of two 150MVA, 110kV XLPE cable circuits in the Liverpool-to-Hobson tunnel directly onto 110/22/11kV transformers at Hobson. 22kV and 11kV switchboards are supplied from the two transformers. Two x 22/11kV transformers also supply the 11kV switchboard at Hobson. Furthermore Freeman's Bay 22kV substation is supplied from the 22kV bus at Hobson.

The bulk supply to Quay substation is from Transpower's Penrose GXP by means of two aged 110kV gas-filled cables directly onto two 50MVA, 110/22kV transformers at Quay. The transformers are rated 50MVA but limited to 30MVA by the capacity of the aged gas-filled cables. A third 110/22kV transformer (60MVA) exists in Quay St substation and supplied from Liverpool via a 110kV XLPE 100MVA rated cable. Parnell 22kV substation is supplied from the 22kV switchboard in Quay.

The geo-schematic in Figure 5-10 below shows the sub-transmission network in and to the Auckland CBD.

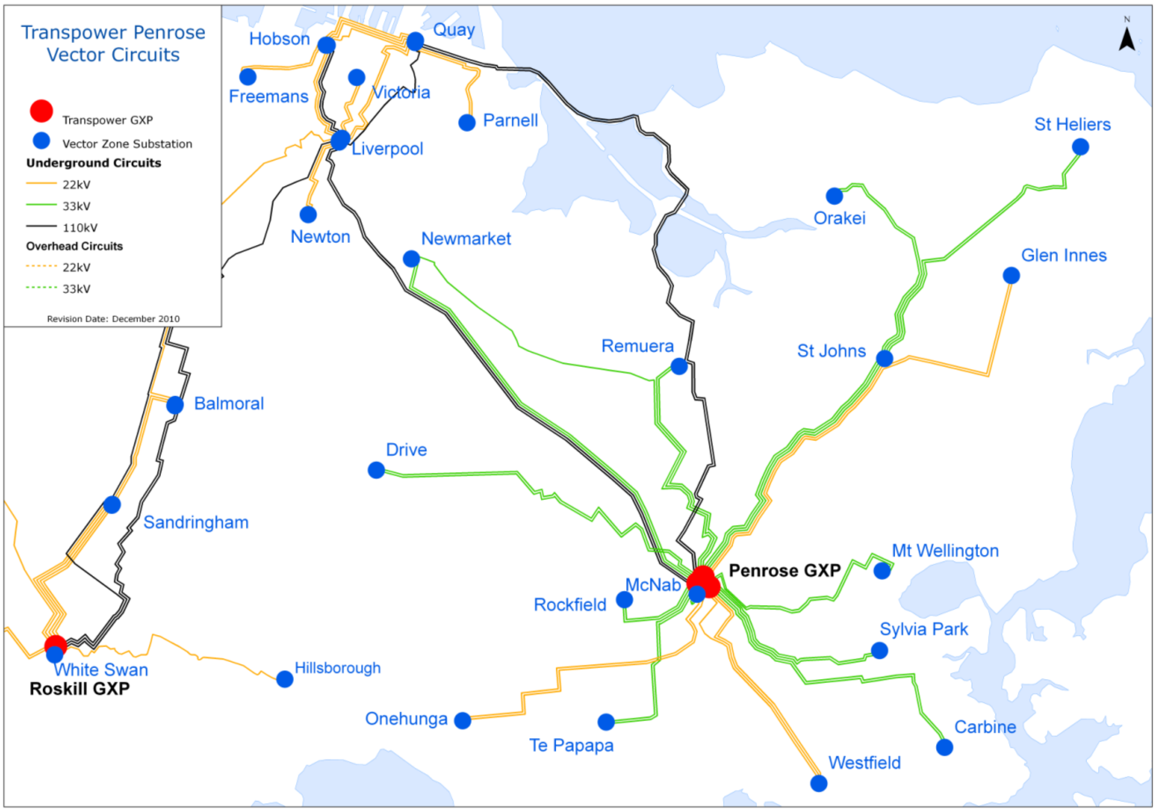


Figure 5-10 : Existing sub-transmission network in and to CBD - geoschematic

Figure 5-11 below is a schematic of the existing sub-transmission network in the CBD. The diagram also shows the sub-transmission circuits from Penrose to Liverpool and from Mt Roskill to Liverpool.

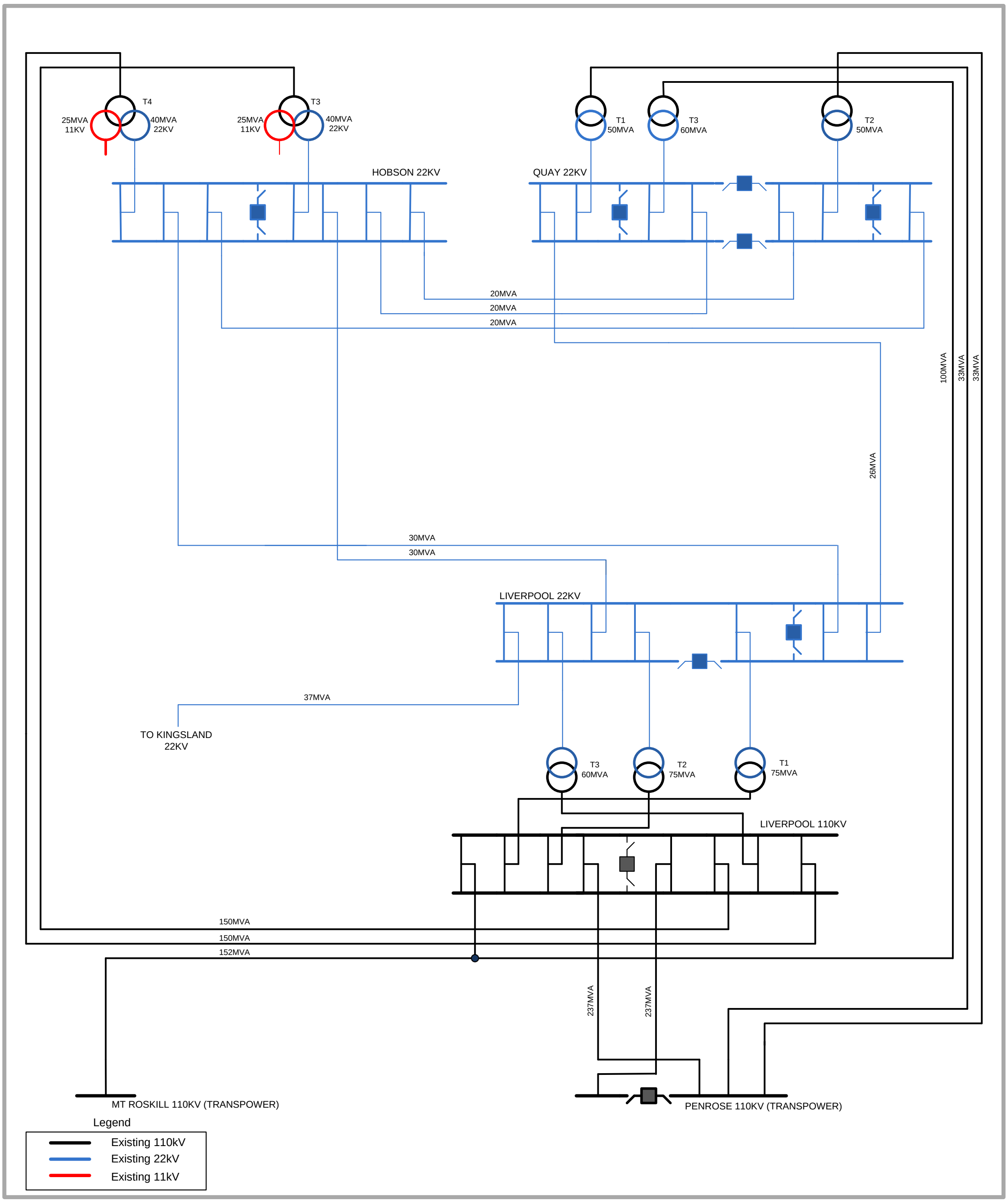


Figure 5-11 : Existing sub-transmission network in and to CBD - schematic

5.9.2 CBD sub-transmission-bulk supply - supply security

The security standard for sub-transmission network in the CBD is “N-1 no break” and “N-2, switched”, with a restoration target time of two hours.

The long-term plan is to install three 60MVA transformers in each bulk supply substation and limit the load to 120MVA in each, to achieve N-1 no-break security. Furthermore, the long-term plan makes provision for the establishment of a 110kV bus at each bulk supply substation, with a 110kV cable ring between the 110kV busbars to provide redundancy in the event of a failure of a 110kV cable circuit. This long-term plan will be implemented through a staged approach, predicated on load growth. The objective of three 60MVA transformers will be met at Liverpool substation in 2011 with the completion of the installation of the 3rd 110/22kV transformer (two of the transformers are actually rated 75MVA[43]).

A new 110/22kV 60MVA transformer has been installed in Quay substation in 2010 with a 2nd 60MVA transformer planned for installation in FY12. After installation of the 2nd 60MVA transformer the two existing aged 110/22kV 50MVA transformers will be retired. A 3rd 60MVA transformer is planned for the long-term at Quay substation.

The two 110/22/11 40/25MVA transformers at Hobson substation are sufficient to provide N-1 security for the short-term. A third 110/22kV 60MVA transformer is planned for installation within the short-term planning period and space will be allowed for this transformer as part of the construction of the new GXP works.

To achieve N-2 switched security for the CBD area, 22kV tie cables have been installed between the 22kV busbars of the CBD bulk supply substations. As load increases, the intention is to establish 22kV ties with a total rating of 60MVA between the 22kV nodes. In the event of a failure of a second 60MVA transformer (i.e. N-2 event), the load can then be transferred to an adjacent bulk supply substation via the 22kV ties. It can be seen in Figure 5-11 above, in which 22kV tie cables are shown, that this goal has been partly achieved.

5.9.3 CBD sub-transmission-bulk supply - load forecast

The peak demand in Auckland’s CBD traditionally occurred in the summer months and more specifically in the period January to around the end of March. However, the present winter and summer loads are very similar. Summer peak demand is primarily caused by air-conditioning plant, and the winter peak through heating. The projected peak demand for the three bulk supply substations in the CBD are shown in Table 5-14, Table 5-15 and Table 5-16.

Hobson substation presently has two 110/22/11kV transformers (T3 and T4), rated at 65MVA each (40MVA at 22kV and 25MVA at 11kV). The installed transformer capacity is 130MVA and the N-1 capacity is 65MVA. The 22kV windings supply the 22kV switchboard and also supplies two 22/11kV transformers (T1 and T2) that supplies the 11kV switchboard. The 11kV windings of the 110kV transformers also supply the 11kV switchboard. Table 5-14 shows the cyclic rating capacity of the two 110/22/11kV transformers and the summer and winter load forecast for the planning period until 2021.

[43] The existing 60MVA 110/22kV transformer will be replaced with a 75MVA transformer to establish three 75MVA transformers of equal impedance at Liverpool. The 60MVA transformer will be relocated to Hobson substation.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Hobson	65	63	64	67	69	72	75	77	79	81	83	85	86
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Hobson	65	63	64	67	69	71	74	76	78	80	82	83	84

Table 5-14 : Summer/winter - load projection: Hobson substation

Liverpool substation has one 60MVA 110/22kV transformer and two 75MVA 110/22kV transformers that supply a double-busbar 22kV switchboard. The total installed transformer capacity is 210MVA and the N-1 capacity is 135MVA. Three 22/11kV transformers are supplied from the 22kV switchboard which in turn supplies an 11kV switchboard. Table 5-15 shows the cyclic rating capacity of the three 110/22kV transformers and the summer load forecast for the planning period until 2021.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liverpool	135	105	107	110	113	115	118	120	123	125	127	129	130
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Liverpool	135	105	104	107	110	112	114	117	119	121	123	124	125

Table 5-15 : Summer/winter – load projection: Liverpool substation

Quay St substation has two 50MVA 110/22kV transformers and one 60MVA 110/22kV transformer. The two 50MVA transformers are limited by the aged gas-filled 110kV cables to which they are connected, to 30MVA each. Theoretically the total installed transformer capacity is 160MVA but is limited to 120MVA by the gas-filled cables. The N-1 capacity is 60MVA. The three transformers supply a double busbar 22kV switchboard. Two 22/11kV transformers are supplied from the 22kV switchboard which in turn supplies an 11kV switchboard. Table 5-16 shows the cyclic rating capacity of the three 110/22kV transformers and the summer load forecast for the planning period until 2021.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Quay Street	60	37	37	39	41	43	44	47	47	49	50	52	53
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Quay Street	60	34	34	36	37	39	40	42	44	46	47	49	50

Table 5-16 : Summer/winter – load projection: Quay substation

Table 5-17 shows the sums of the demands of the three CBD bulk supply points for 2010 and the load projection for the CBD for the planning period.

Name	Capacity	Actual load 2010	Forecast - Summer MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CBD Total	320	204	208	216	222	230	236	244	249	255	260	266	269
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
CBD Total	320	202	203	210	215	222	228	235	241	246	252	257	259

Table 5-17 : Auckland CBD bulk supply - load projection

5.9.4 CBD sub-transmission-bulk supply – development strategy

The long-term strategy is to establish a CBD network that has full no-break N-1 capacity and switched N-2 capacity. This strategy has been partly achieved but the CBD supply would still be vulnerable to the loss of supply from Transpower Penrose. Examples of possible HILP events are loss of Transpower's 110kV bus at Otahuhu, loss of Transpower's Penrose substation or failure of both of Vector's 110kV cables in the Penrose tunnel. The dependency on Penrose for the CBD supply has been recognised and is considered in the development strategy for the CBD.

Limited backstop capacity to mitigate a Penrose supply loss is by means of a 152MVA 110kV cable from Mt Roskill to Liverpool substation and a 37MVA 22kV cable from Kingsland to Liverpool substation. These two backstop circuits will not provide the full demand of the CBD during peak periods – this would currently be achieved through using the two aged 110kV gas-filled cables from Penrose to Quay St (limited to 30MVA each).

In 2014, once the Hobson GXP is in operation, these cables will be retired. Kiwirail is, however, planning to raise the bridge-over-rail in Orakei Rd in 2012 where the two gas-filled cables cross the railway line, requiring possible rerouting of these cables. Should this eventuate, it is likely that alternative contingency strategies will be investigated to ensure a switched N-2 supply level to the CBD can be maintained until 2014, rather than incur the (high and soon to be sunk) cost involved with shifting the gas cables.

A new 110/22kV 60MVA transformer was commissioned at Quay St substation in 2010, supplied via a new 110kV XLPE circuit from Liverpool substation. This transformer, together with the two 50MVA transformers, provides N-1 no-break capacity for Quay St substation. A second 110/22kV 60MVA transformer is planned for installation in Quay St in 2012 after which the two aged 50MVA 110/22kV transformers will be retired. A third 110/22kV 60MVA transformer is planned for the long-term as required by load growth. Figure 5-10 above shows the existing sub-transmission network and bulk supply points to the Auckland CBD in schematic format - the diagram includes the 110kV XLPE cable circuit from Liverpool substation that was commissioned in 2010.

The new GXP at Hobson is scheduled to come on-line in June 2014. Vector will establish a new 110kV node (GIS switchgear) at the substation, which will enable it to be supplied from either Penrose or Albany via the 220kV NAaN cable circuit. This will fully address the HILP risk to the CBD supply, discussed above. Transpower's 250MVA 220/110kV interconnecting transformer at Hobson substation will be sufficiently rated to supply the load at Hobson substation as well as the load at Liverpool substation and Quay St substation in the event of a failure of Transpower's Penrose 110kV bus or failure (HILP event) of the two Penrose to Liverpool 110kV circuits.

An 110kV circuit to Quay from Hobson will be installed following the completion of the GXP and 110kV node at Hobson substation. The necessary underground ducts for the

110kV cable are already in place between Hobson and Quay St substation. Currently, for loss of the 110kV supply to Quay St from Liverpool, the 22kV intertie cables from Hobson will be used to supply load at Quay St substation supported by the 110kV Penrose to Quay cables. The ability to transfer load from Hobson to Quay St via the 22kV intertie cables will be limited by the capacity of the two 65MVA, 110/22/11kV transformers at Hobson.

Figure 5-12 depicts the intended sub-transmission network into the CBD after completion of the new GXP and Vector's associated works at Hobson. At the same time that the second 60MVA transformer is installed at Quay St the existing (aged) 50MVA transformer will be decommissioned and scrapped.

As stated above, a 2nd 60MVA 110/22kV transformer at Quay St substation, supplied from the existing cable will provide N-1 redundancy for failure of a transformer at Quay but the substation will be vulnerable for failure of the 110kV cable from Liverpool.

Two high-impedance 75MVA 110/22kV transformers were installed at Liverpool substation in FY11 to replace two transformers. One 60MVA transformer remains at Liverpool but due to an impedance mismatch between the existing and new[44] transformers this transformer will be replaced with a third 75MVA high-impedance transformer, in the AMP planning period. The N-1 capacity at Hobson will then be 150MVA. The existing 60MVA transformer will be redeployed at Hobson substation to establish a third 110/22kV transformer at Hobson.

In the same period, it is anticipated load growth at Hobson will require the installation of a third transformer rated 60MVA, 110/22kV (ex-Liverpool). Figure 5-12, depicts the sub-transmission network into the CBD after the planned installation of the 110kV XLPE circuit from Hobson to Quay St and the third 60MVA 110/22kV transformer (T5), at Hobson substation.

Future load-growth at Quay St is expected to require the installation of a 110kV GIS bus at Quay. (KiwiRail has approached Vector with regard to a 36MVA supply for rail electrification for the CBD's rail network and future expansion of this network. Ports of Auckland (POA) have also approached Vector with regard to extensions at the Auckland port.) A third 60MVA 110/22kV transformer will be installed over the long-term at Quay St, to meet actual load demands – this will determine the timing of the 110kV bus at Quay St.

[44] The new 75MVA 110/22kV transformers have 28% impedance to reduce the fault levels on the Liverpool 22kV switchgear

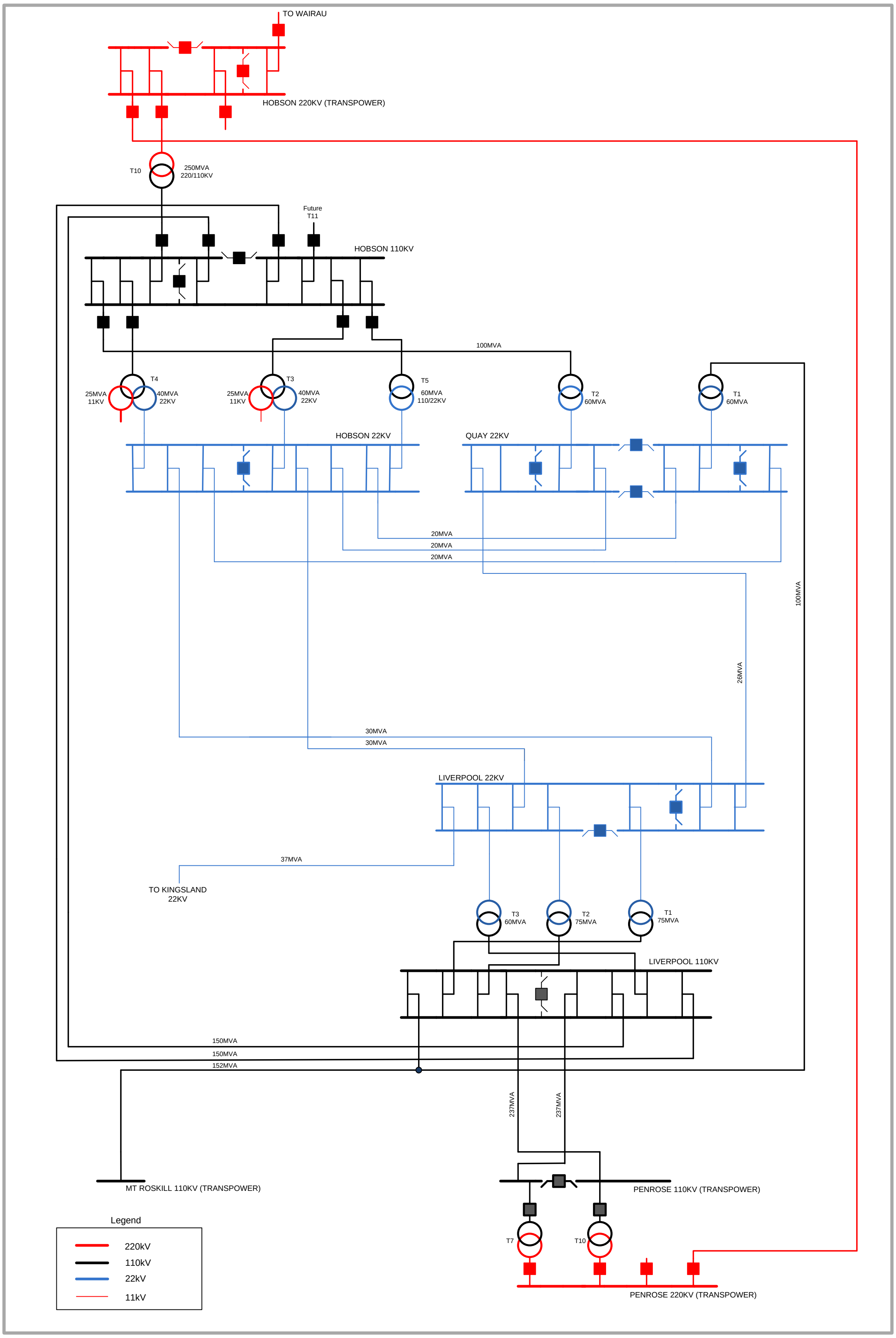


Figure 5-12 : Sub-transmission network in and to CBD - post 2015

In the long-term, the network development strategy for the CBD (towards the end of the AMP planning period) provides for the establishment of a further CBD zone substation in the area around the southern end of Hobson and Nelson Streets and around Cook St. This substation will be designated Hobson-West and a site for this substation has already been secured in Hobson St, with the appropriate consents and designation in place with the Auckland City Council. This substation will initially be developed as a 22kV node by connecting into the existing 22kV intertie cables between Hobson and Quay substations but as load grows will be developed into a 110kV supplied zone substation.

The long-term plan also makes provision for the installation of a 22kV switchboard at Victoria substation. Victoria substation presently operates at 11kV and supplies commercial load in the eastern parts of the Auckland CBD (Figure 5-12 above shows the location of Victoria substation). With the long-term strategy of migrating to a 22kV distribution network in the CBD, this substation is strategically located as a marshalling point for the 22kV network. The existing aged 22kV intertie cable between Quay and Liverpool substations will be replaced and used to supply the proposed 22kV bus at Victoria substation.

Figure 5-13 depicts the planned sub-transmission network in the CBD over the long-term.

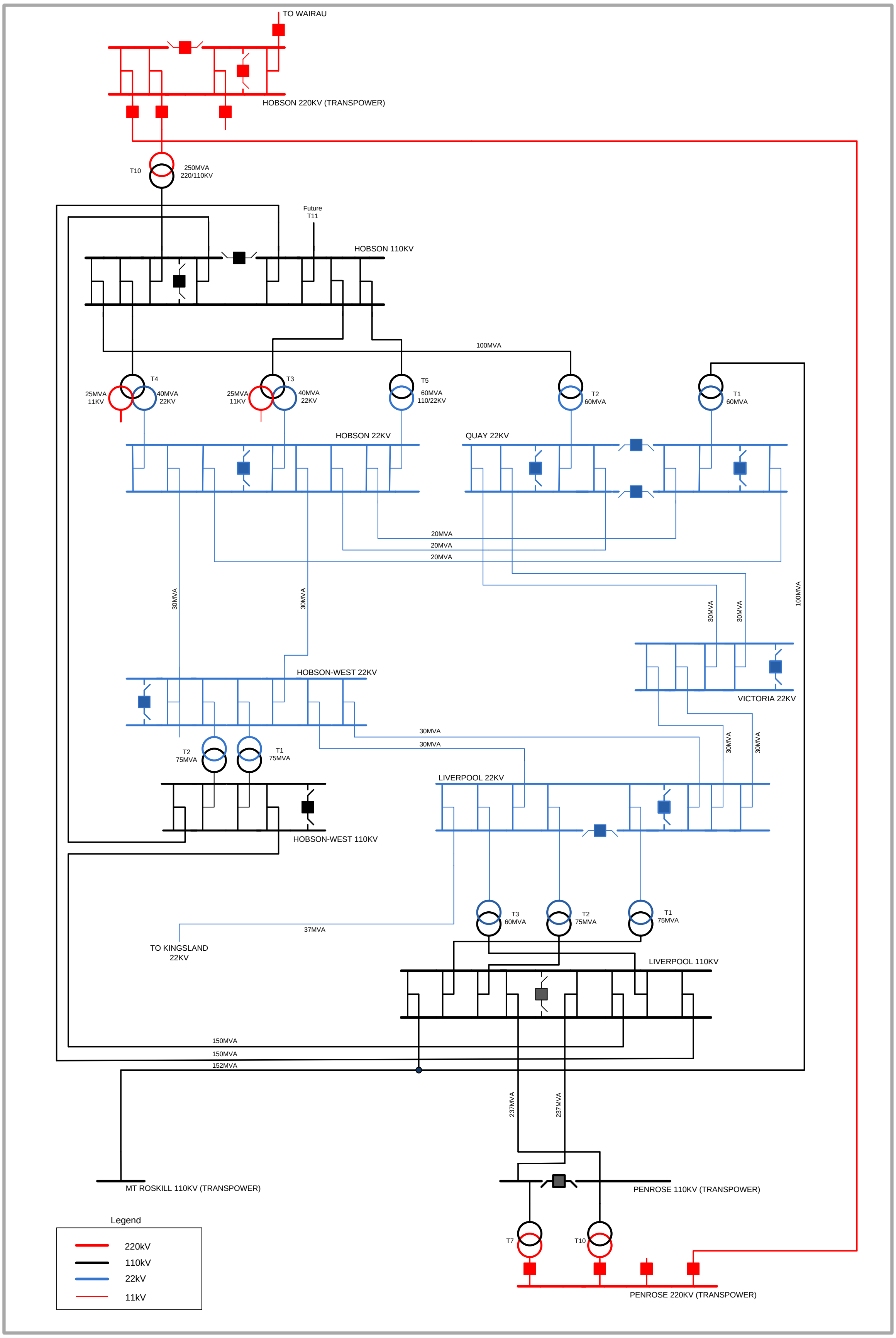


Figure 5-13 : Sub-transmission network in and to CBD – long-term

5.9.5 CBD sub-transmission-bulk supply – projects

a. Projects – within five years

Hobson substation	Establish a 250MVA 220/110kV GXP including civil works and ancillary works and install a new 110kV GIS switchboard and transfer the existing 110kV cables to the 110kV GIS. Scheduled commissioning date for the GXP is June 2014.
Hobson substation	Install a 3rd 60MVA 110/22kV transformer to upgrade the transformer security to N-1.
Quay substation	Install a 2nd 60MVA 110/22kV transformer. This transformer will be supplied from the existing 100MVA 110kV XLPE cable from Liverpool.
Quay substation	Phase 1 of extending the 22kV switchboard to provide feeders for future network reinforcement.
Roskill substation	Upgrade the 110kV disconnector on the Roskill to Liverpool 110kV feeder in the Transpower bay to the emergency rating of Vector's 110kV cable.
Penrose substation	Upgrade the 110kV disconnectors on the two Penrose to Liverpool 110kV feeders on Transpower's 110kV bus to the emergency rating of Vector's 110kV cables in the Penrose tunnel.
Hobson to Quay	Install a 110kV 1000mm² XLPE cable from Hobson to Quay to the 2nd 60MVA transformer and remove the existing aged 50MVA transformer. The two existing aged gas-filled 110kV cables will be retired in conjunction with this project.
Liverpool substation	Replace the aged third 60MVA transformer (T3) with a new 75MVA transformer with impedance that matches transformers T1 and T2.
Penrose to Hobson	Install EMF short circuiting loops at 110kV joints in the Penrose to Hobson tunnel to mitigate EMF levels for future installation and maintenance works.
Penrose to Hobson	Upgrade the water fire suppression system at 220kV NAaN cable joints.

b. Projects – within five to ten years

Liverpool substation	Extension of the 22kV switchboard to cater for the conversion of the 11kV network in the CBD to 22kV.
Hobson substation	Extension of the 22kV switchboard to cater for the conversion of the 11kV network in the CBD to 22kV.
Quay substation	Construct a 110kV switchgear building and install a 110kV GIS switchboard.

c. Projects – long-term

Quay substation	Second stage of the extending of the 22kV switchboard to provide feeders for future network reinforcement.

Hobson to Quay	Install a 2nd 110kV XLPE cable between Hobson and Quay substation to upgrade the security on the 110kV network to Quay to full N-1 status.
Hobson West substation	Establish a 110/22kV bulk supply substation in the lower Hobson, Nelson and Cook St precinct.
Victoria substation	Installation of a 22kV switchboard to establish a distribution node.

5.10 Sub-Transmission – Southern Network

5.10.1 Southern sub-transmission and bulk supply - background

The Southern network has eight GXPs; Hepburn, Roskill, Penrose, Pakuranga, Mangere, Otahuhu, Wiri and Takanini. Although the CBD is geographically viewed as being in the Southern region it is described separately above for the reason that the network in and to the city is more complex, extensive and load intensive. A GXP exists in Tokoroa to supply a Fonterra facility (Lichfield GXP). One bulk supply substation, Pacific Steel, exists in the Southern region.

5.10.2 Southern sub-transmission and bulk supply – development strategy

No GXPs are planned in the Southern region for the short-term planning period.

A GXP is planned at Southdown in the long-term (2026) and in the southern precinct of Newmarket (2020) which will take load off the Penrose GXP. In line with the development strategy for the sub-transmission network the capacities of the future GXPs will be limited to 120MVA. Load at the Penrose GXP will be limited to 240MVA.

Vector owns and operates two 110kV 0.25 inch² Copper-conductor oil-filled cables with summer/winter ratings of 80/51MVA from Roskill GXP to Kingsland substation. The cables connect to two 60MVA 110/22kV transformers.

5.10.3 Sub-transmission and bulk supply – proposed projects

a. Projects – within five years

Pakuranga	Replace 33kV switchboard and install 3rd 220/33kV transformer (Transpower project).
Penrose	Replace 33kV switchboard (Transpower project).
Wellsford	33kV: Alleviate transformer bay constraint.
Takanini	33kV: Alleviate transformer bay constraint.
Mangere	33kV: Alleviate transformer bay constraint.
Otahuhu	22kV: Alleviate transformer bay constraint.

b. Projects – within five to ten years

Otahuhu	Install a third transformer.
Mangere	Install a third 110/33kV transformer.
Wiri	Replace two existing 110/22kV transformers.
Mt Roskill	Replace the existing 50MVA transformer.

c. Projects – long-term

Although the long-term projects fall outside the planning period of the AMP, preliminary indications are that the following projects will be required between 2020 and 2030. (This may influence interim network developments as well.)

Newmarket South	Establish a 110/33kV bulk supply point at Newmarket South.
Southdown	Establish a new 220/33kV GXP.
Browns Hill	Establish a new 220/33kV GXP.
Huapai	Establish a new 220/33kV GXP.

5.11 Auckland CBD Distribution Network

At present the bulk of the load in Auckland CBD is supplied by the 11kV distribution network, supplied from four zone substations, Hobson, Liverpool, Victoria and Quay. The distribution network comprises 11kV radial feeders from the four zone substations, forming a meshed network with open switch points between feeders.

From 2004, further development of the 11kV distribution network in the Auckland CBD was suspended in favour of the progressive roll-out of a 22kV distribution network. This was required to provide sufficient capacity and security to meet load growth in CBD over the longer-term, and was more cost-effective than further expanding the 11kV network. All further distribution network developments in the CBD are, therefore, done with 22kV rated equipment, even where these temporarily replace 11kV assets. Development work in the CBD as far as possible leverages off road rehabilitation works being carried out by Auckland Transport (and work carried out by other utilities).

As a long-term strategy, where possible all new CBD connections will be made to the 22kV network, while existing 11kV substations will be progressively transferred to the 22kV network as the 11kV assets reach the end of their economic lives, or when additional distribution capacity is required to cater for demand growth. Figure 5-14 indicates the planned extent of the future 22 kV network in the CBD.

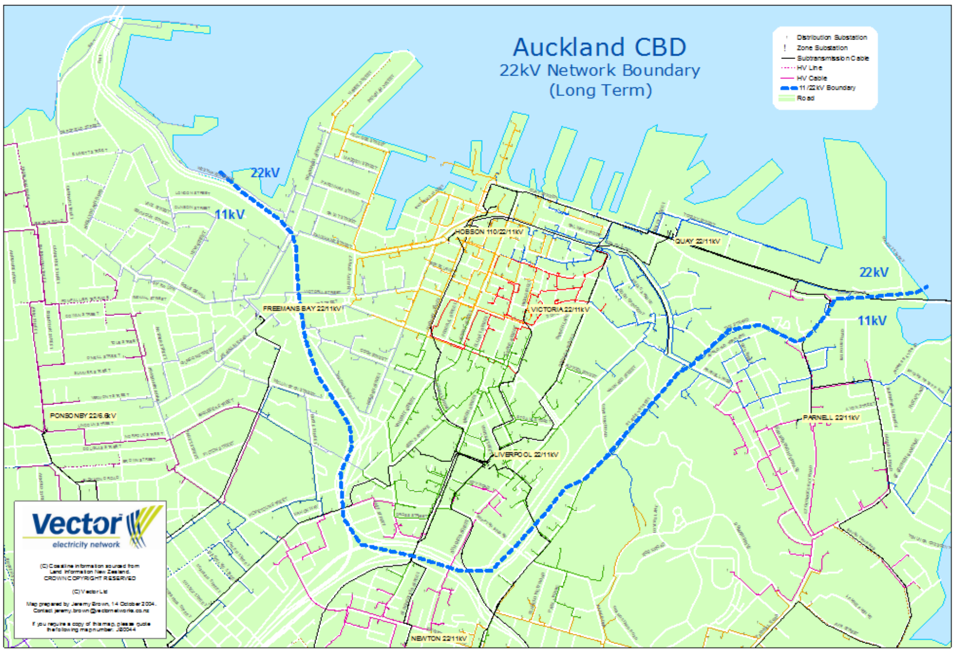


Figure 5-14 : Area designated for 22kV distribution

5.11.1 CBD Distribution Projects

- Auckland CBD 22kV network extension and 11kV to 22kV load transfer (ongoing)

  Vector will be progressively replacing 11 kV assets and installing 22 kV assets for new connections in the CBD. These projects will be carried out based on customer identified needs, or as assets reach the end of their useful lives.

- Hobson - 22kV extension to Tank Farm (ongoing)

  AWDA (Auckland Waterfront Development Agency) plans to progressively develop the Tank Farm area into a commercial hub over a 15 year timeframe. The existing 11kV network capacity is insufficient to supply the projected load arising from this development. Two 22kV distribution feeders were installed from Hobson substation to the Fanshawe Street/Beaumont Street area in 2008, with the intention of extending them further northwards when customer load dictates. A third 22kV feeder is planned for the future, again driven by customers' load requirements.

- Quay substation - extension of the 22kV switchboard (2014)

  It is proposed to extend the 22kV switchboard at Quay St to increase the number of 22kV distribution feeders available at this substation. This is required for the progressive roll-out of the 22kV network in the CBD. Additional 22kV capacity has been installed with the recent installation of the new 60MVA transformer.

- Freemans Bay - 22kV extension at Union Street to offload Freemans Bay feeder 13 & 15 (2014)

  The CBD load forecast indicates Freemans Bay feeders 13 and 15 will be short of backstop capacity from 2014. As part of the load supplied by Freemans Bay feeders 13 and 15 are in the designated CBD area. It is proposed to extend the 22kV distribution network to offload these two feeders.

  (The alternative of extending new 11kV feeders from Freemans Bay substation to solve the security shortfall was considered but this option is less cost efficient, and not in line with Vector's long-term strategy for CBD distribution.)

- Liverpool – New 22kV feeders to Telecom Mayoral Drive (2016)

  The Telecom Exchange in Mayoral Drive is supplied by 11kV feeders from Liverpool substation, with a current demand of 5MVA. Telecom plans to progressively expand the exchange and has indicated a long-term forecast demand of up to 20MVA. This will require two new 22kV feeders from Liverpool substation. As it is a customer driven project, the timing is subject to customer's requirements, but at this stage it is scheduled for 2016.

- Parnell – New 11kV feeder to offload Newmarket feeders 6 & 12 (2016)

  Two feeders supplying Broadway on the Parnell side, Newmarket feeders 6 & 12, are heavily loaded and are forecast to be short of backstop capacity in 2016. It is proposed to install a new 11kV feeder from Parnell substation and redistribute the load on existing feeders.

  The alternative of a new 11kV feeder from Newmarket substation would initiate civil works to extend the switch room at Newmarket to accommodate an additional circuit breaker, which would results in a higher cost option than the feeder from Parnell substation.

- Hobson - extension of the 22kV switchboard (2016)

  This project proposes extending the 22kV switchboard at Hobson substation to cater for the increased 22kV distribution capacity requirements in the CBD. This project is linked with the upgrading of this substation to a grid exit point in 2014, and the installation of an additional 110/22kV transformer for additional capacity. It is also required for the progressive conversion of the CBD distribution voltage to 22kV.

- Quay - Ports of Auckland supply (2017)

  Ports of Auckland have provided Vector with their ten year plan for the development of the electrical supply to the Quay St port facility. Currently, the demand is expected to increase to 11MVA by 2017, increasing to 20MVA in the mid-term. To meet the projected demand requirements, a new 22/11kV zone substation is anticipated. (Note that this is a customer driven project, so the timing and proposed solution are provisional at this stage.)

- Newton – New 11kV feeder to backstop Newton feeders 9 and 22 (2019)

  A new 11kV feeder is proposed to solve a projected security shortfall on Newton 11kV feeders 9 and 22.

- Liverpool - Medical School supply stage 2 (2015)

  A new 11kV feeder from Liverpool substation to the Medical School in Grafton will be required to meet load growth arising from the forecast expansion plans. This load is expected to increase to 7MVA by 2015. (This is a customer driven project and the timing is provisional.)

- Hobson/Quay - Queens Wharf supply (2021)

  A new 22kV distribution feeder is to be installed to supply the Queens Wharf development. (Timing is dependent on the customer and is, therefore, provisional at this stage.)

5.12 Penrose GXP Area Development Plan

5.12.1 Bulk Supply

5.12.1.1 Background

Vector takes supply from Penrose GXP at 110kV for bulk supply to the Auckland CBD, and at 33kV and 22kV for local distribution to a number of zone substations in the area surrounding the substation.

- The 110kV bus is connected to TP Pakuranga, TP Otahuhu and a 220/110kV 200MVA interconnector at Penrose substation.
- The 33kV bus is supplied by two 220/33kV 160MVA transformers and a third 220/33kV 200MVA transformer.
- The supply to the 22kV bus is from the 33kV bus via three 33/22kV 45MVA auto transformers.

These are all Transpower owned assets.

The geo-schematic in Figure 5-15 below shows the existing 110kV, 33kV and 22kV sub-transmission networks supplied from this GXP.

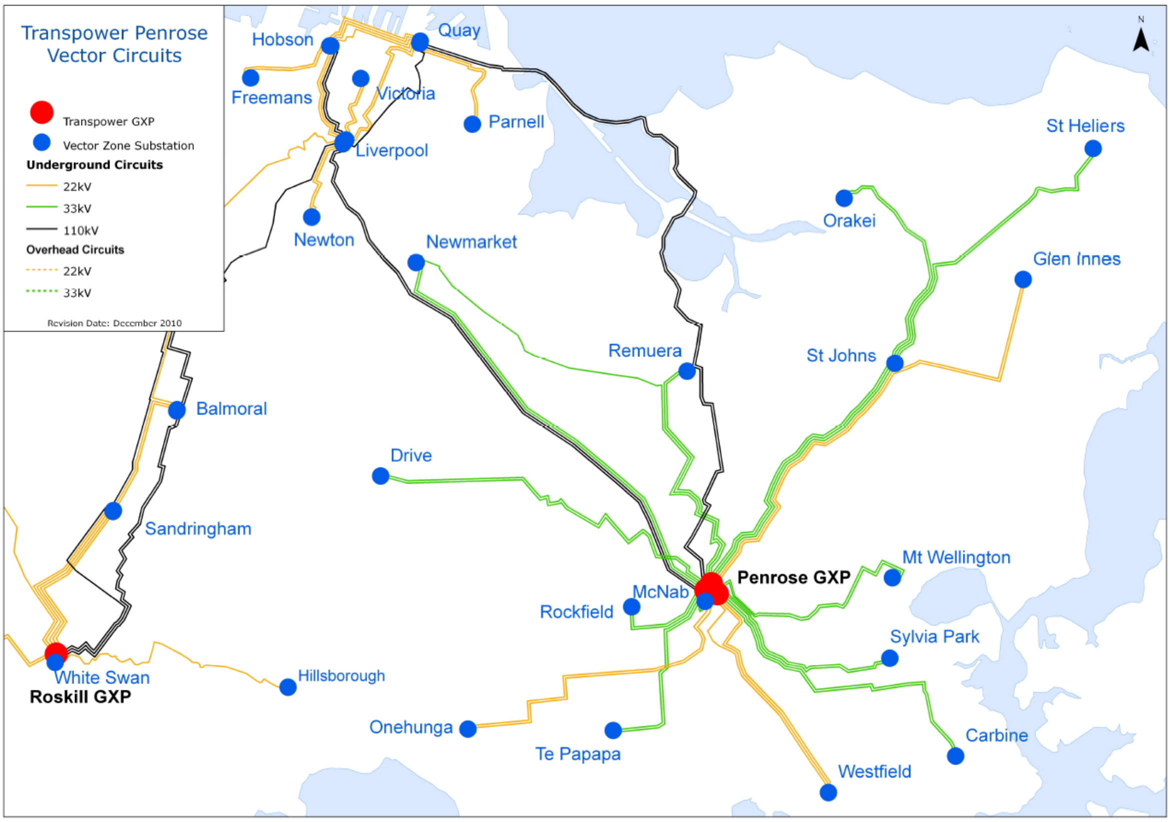


Figure 5-15 : Existing sub-transmission network at Penrose GXP

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Penrose 110kV		216	218	227	234	242	248	256	262	267	273	279	282
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Penrose 110kV		191	192	198	204	210	215	222	228	233	238	243	245

Table 5-18 : Load forecast for Penrose GXP

The long-term plan is to progressively transfer load from the Penrose 22kV bus to the Penrose 33kV bus in conjunction with the 22kV asset replacement programme. The intention is to reduce the load on the 33kV bus through the establishment of a new GXP at Southdown and Newmarket-South (to be established). (A 220kV GXP already exists at Southdown, but Vector does not take a supply from it.) The intended impact of this work on alleviating the load at Penrose GXP is indicated in Table 5-19.

GXP	Forecast - Winter MVA										
	2019	2020	2021	2022	2023	2024	2025	2026	2035	2045	2055
Newmarket South		54	55	57	58	59	60	78	106	112	119
Southdown								36	102	108	115
Penrose 33kV	363	316	319	321	323	325	327	276	205	218	231

Table 5-19 : Proposed load reduction at Penrose GXP

5.12.1.2 Bulk supply projects for the planning period

a. Projects – Within next five years

- Penrose 33kV GXP – Transpower to install new 33kV board (2012)

  Transpower plans to install a new indoor 33kV board to replace the existing 33kV outdoor structure. Vector's existing 33kV sub-transmission cables need to be relocated and re-terminated accordingly.

b. Projects – Within five to ten years

- Establish Newmarket GXP (2020)

  It is proposed to establish a GXP at Newmarket to supply high density commercial/industrial load in the area. The long-term strategy is to transfer load from the Penrose 33kV bus to the proposed GXP (as well as later on to a proposed Southdown GXP) as sub-transmission assets are retired and replaced due to age/condition (see Table 5-19 above).

5.12.2 Penrose 22kV Sub-transmission Network

5.12.2.1 Background

Penrose 22kV GXP supplies three zone substations, viz. Glen Innes, Onehunga, and Westfield. Table 5-20 shows the summer and winter load forecasts at the GXP.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Penrose 22kV	90	53	47	48	49	50	51	52	52	53	54	54	54
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Penrose 22kV	90	56	46	47	48	49	49	50	50	51	51	52	52

Table 5-20 : Summer and winter load forecasts at Penrose 22kV GXP

5.12.2.2 Projects Planned

No expenditure is forecast within this planning period on the Penrose 22kV sub-transmission network.

5.12.3 Penrose 33kV Sub-transmission Network

5.12.3.1 Background

Penrose 33kV GXP supplies 12 zone substations, viz. Carbine, Drive, McNab, Mt Wellington, Newmarket, Orakei, Remuera, Rockfield, St Heliers, St Johns, Te Papapa and Sylvia Park. It also supplies a 33kV switching station at St Johns and the 22kV board supplying Glen Innes, Onehunga and Westfield.

Table 5-21 shows the summer and winter load forecasts at the GXP.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Penrose 33kV Combined	406	275	269	278	286	293	302	311	320	329	336	342	345
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Penrose 33kV Combined	428	315	301	307	313	318	326	334	342	350	357	363	366

Table 5-21 : Summer and winter load forecasts at Penrose 33kV GXP

5.12.3.2 Projects planned

a. Projects – Within next five years

- Newmarket South – land purchase (2012)

  It is planned to establish a new substation in the Newmarket South area (refer to Newmarket South substation below) in 2016. Land will need to be purchased land for this purpose in 2012.

- Te Papapa - 11kV reinforcement (2014)

  Demand arising from incremental load increases from industrial customers around the Alfred Street area is expected to exceed the capacity of the Te Papapa feeder 11 by 2014. Load transfers are impractical as adjacent feeder Onehunga 8 is already heavily loaded. The proposed solution is to install a new 11kV feeder from Te Papapa substation and re-distribute the load on the existing network in 2014. Completion of the project will solve the security shortfall problem in the area.

  (An alternative option is to connect the feeders to Onehunga substation. This option is not preferred due to capacity constraints at Onehunga substation due to sub-transmission cables ratings.)

- Remuera – 11kV feeder reinforcement to offload Remuera feeders 11, 12 and 17 (2015)

  Load on Remuera feeders 11, 12 and 17 is expected to exceed 85% of feeder capacity from 2015. Load transfer to adjacent feeders has been investigated but is impractical due to lack of accessible adjacent feeders. A new cable extending from Rockfield feeder 13, extending to Remuera feeder 12, is proposed in 2015. Load redistribution will follow. This project will take advantage of load diversity between the two feeders as Rockfield feeder 13 has commercial/industrial load characteristic while Remuera feeder 12 is residential.

  A new feeder from Remuera substation is an alternative, but would be considerably more costly.

- Sylvia Park – New 11kV feeders to offload Westfield feeders (2013)

  Four feeders at Westfield substation, Westfield 2, 8, 14 and 18, are heavily loaded and will exceed 80% - 90% of feeder capacity from 2013. Transfer of load onto adjacent feeders has been investigated and dismissed as an option. Two new 11kV feeders are proposed from Sylvia Park substation to offload the Westfield feeders 2, 8 and 18 in 2013.

  Installing new feeders from Westfield substation was investigated as an alternative, but was discounted as a costlier option.

b. Projects – Within five to ten years

- Newmarket South – establish a new substation (2016)

  The existing supply to Newmarket is from a three transformer substation in Gillies Avenue. Current load is 37MVA on three 20MVA transformers. The load has decreased with the progressive relocation of Lion Breweries to Ormiston Road, but a combined residential/commercial development is planned. Newmarket substation is ideally suited to supply this site.

  Westfield has indicated further load increases for its shopping mall at the south end of Newmarket, which cannot be met from the existing substation. Feeders from the adjacent Remuera and Drive substations are heavily loaded, and while an option remains to install additional feeders, there is insufficient capacity at these substations to meet the additional demand. These substations are also distant from the commercial load centre in Newmarket.

  A new zone substation (Newmarket South substation) is, therefore, proposed at the south end of Newmarket with a commissioning date of 2016. The supply to Newmarket South substation will initially utilise Newmarket's 33kV feeders until capacity constraints dictate an upgrade. Establishing a new GXP at Newmarket South supplied from Penrose 110kV is proposed for 2020.

  The new substation was initially planned to be commissioned in 2014. The project has now been deferred to 2016 because the load growth has been lower than forecast due to the economic downturn and delays in the customer driven Westfield Mall development.

  With Newmarket South substation established, and after the ex-Lion Breweries site is developed, Newmarket substation will be located at the load centre. Newmarket South will offload Remuera and Drive substations and supply the Westfield complex.

- Ellerslie – establish a new zone substation (2018)

  Forecast load growth associated with the commercial development at Ellerslie racecourse, will require the establishment of a new Ellerslie zone substation. It will provide capacity to offload heavily loaded feeders from adjacent substations of Remuera, McNab and Drive. The new substation was initially planned to be commissioned in 2015, but was subsequently deferred to 2018 due to deferral of the Ellerslie racecourse development.

  Alternative options investigated include the installation of additional feeders from McNab substation. However, McNab is already a three transformer substation and supplies adjacent industrial areas. Adding the Ellerslie load onto McNab (43MVA on three 20MVA transformers) will cause this substation to breach security levels.

  Adding Ellerslie demand to Remuera, Drive, or Rockfield substations is another option reviewed. Remuera, Drive and part of Rockfield's load is residential load and adding further transformer capacity to cater for the additional Ellerslie load will push fault levels to unacceptable levels. Any capacity increases at these substations will initiate substantial upgrading work including building alterations to accommodate additional switchgear, new 11kV switchgear with higher current ratings and the installation of long sub-transmission and distribution cables. These options are more costly compared with constructing Ellerslie substation.

- St Johns - additional 33kV circuit (2018)

  St Johns substation is a 33kV switching station supplying St Johns, Orakei and St Heliers substations. Load increases at these substations are causing security constraints on the Penrose to St Johns 33kV feeder circuits. An additional 33kV circuit from Penrose 33kV GXP to St Johns switching station is required to relieve this constraint. The new circuit was planned to be commissioned in 2014 but has been deferred to 2018.

- Rockfield - extend NZFP feeders to offload McNab feeders (2013)

  Load on McNab feeders 8 and 16 has reached 90% and 80% of feeder capacity, respectively, in 2010. A backstop security shortfall on McNab feeder 29 is expected from 2020. Load transfers can be implemented to solve the problem in the short-term, but to meet long-term security new capacity is required to offload the feeders. It is proposed to extend the ex-NZFP feeders (Rockfield) to offload the McNab feeders. The ex-NZFP feeders are spare at present after the departure of this customer.

  Alternative solutions investigated include the installation of new feeders from McNab or Rockfield substations. These options are costlier than the proposed solution.

- Newmarket - ex Lion Breweries site development supply (2021)

  Extend existing 11kV feeders from Newmarket to supply load arising from the re-development at the ex-Lion Breweries site in Newmarket. The timing of this project is subject to the customer’s development timeframes.

5.12.4 Roskill GXP

5.12.4.1 Background

Roskill GXP provides a 110kV supply to Kingsland 110/22kV substation and a separate 22kV supply to a number of Vector substations. Vector also takes a 110kV supply to the 110kV bus at Liverpool in the CBD, supporting the existing dual 110kV supplies from Transpower Penrose via the tunnel. The sub-transmission network fed from Roskill is indicated in Figure 5-16.

To meet the forecast load growth, the long-term plan is to upgrade Roskill sub-transmission voltage from 22kV to 33kV. Where sub-transmission assets are retired and replaced, or upgraded, 33kV rated assets are installed, and operated at 22kV.

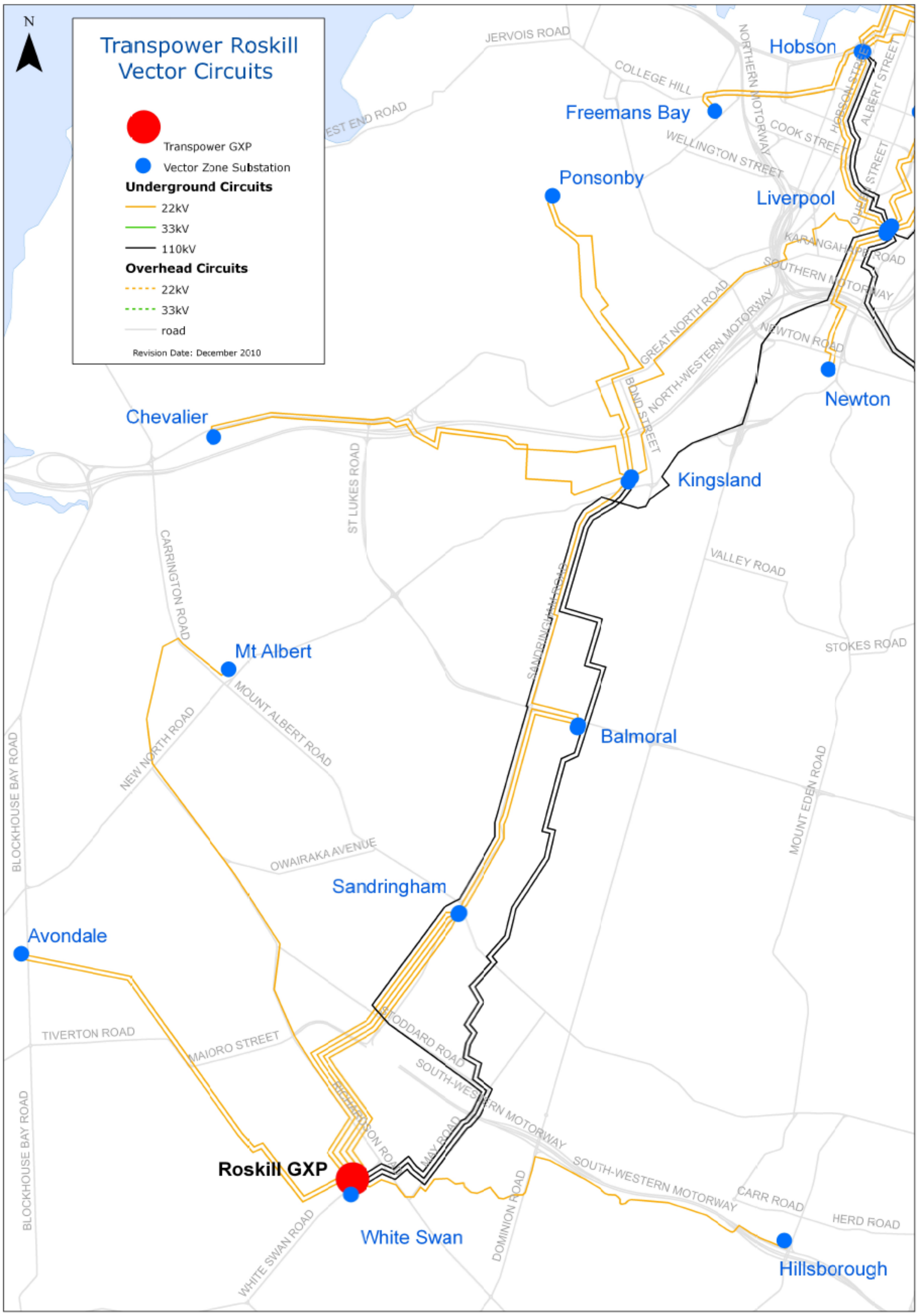


Figure 5-16 : Existing sub-transmission network at Roskill GXP

5.12.5 Kingsland Sub-transmission Network

5.12.5.1 Background

There are two 110/22kV 60MVA transformers and two 22/11kV 20MVA transformers installed at this substation. Two 22/11kV transformers (Kingsland zone substation) are supplied from the 22kV switchboard. Two zone substations, Chevalier and

Ponsonby, are remotely supplied from the Kingsland 22kV switchboard via 22kV cables. Table 5-22 shows the summer and winter load forecasts at the substation 22kV switchboard and the sub-transmission network fed from Kingsland is shown in Figure 5-17.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Kingsland 22kV		36	35	36	37	38	39	39	40	40	40	41	41
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Kingsland 22kV		54	53	53	54	54	55	56	56	56	57	57	58

Table 5-22 : Summer and winter load forecasts at Kingsland substation 22kV switchboard

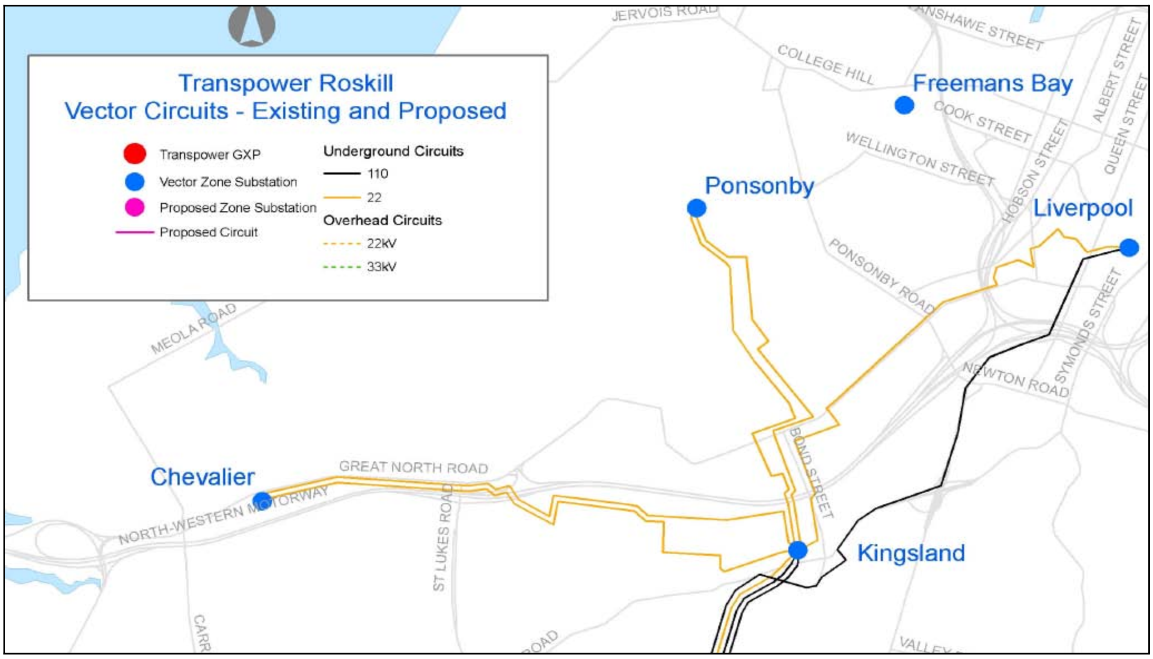


Figure 5-17 : Existing sub-transmission network connecting to Kingsland 110/22kV substation

5.12.5.2 Projects Planned

a. Projects – Within next five years

- Waterview tunnel supply (2011 - 2015)

  The New Zealand Transport Authority (NZTA) plans to build a road tunnel on SH20 between Waterview and Sandringham. The project comprises two phases, provision of power supplies to construct the tunnel and motorway, and the permanent power supply necessary to meet the operational requirements of the tunnel. Table 5-23 summarises the power requirements of each phase:

North Portal Supply		
Construction	Load	9.0MVA (combined)
	Timeframe	Q3 2011 to 2015
Permanent	Load	4.0MVA
	Timeframe	2015
	Security of Supply	N-1 with auto switching
	GXP	Hepburn or Henderson

South Portal Supply		
Construction	Load	8.0MVA (combined)
	Timeframe	Q3 2011 to 2015
Permanent	Load	4.0MVA
	Timeframe	2015
	Security of supply	N-1 with auto switching
	GXP	Roskill

Table 5-23 : Power supplies required for the Waterview tunnel

There is insufficient capacity within the existing network to meet the tunnel demand for both the construction and permanent supplies. Reinforcement is required.

A variety of options have been investigated to provide the capacity necessary for the construction supply while avoiding asset stranding on completion of this phase of the project. Further synergies have been investigated to leverage off other planned projects to arrive at the most favourable outcome that provides the optimal and cost efficient solution. The preferred long-term plan is outlined below:

- Chevalier - second transformer and two 11kV new feeders (2012)

The additional demand required for the construction supply at the north portal will breach security levels at Chevalier substation. Installing a second 22/11kV transformer at Chevalier substation and two new 11kV feeders to supply the north portal construction load is proposed. One of the new feeders will supply the construction load at the north portal, and the other to offload Avondale substation. This will release spare capacity at Avondale substation to supply construction load at the south portal. This phase of the project is planned to be completed in the third quarter of 2011.

Once the northern portal permanent supply is connected, the construction supply capacity at Chevalier will become available. This capacity will be used to support load from Mt Albert and Rosebank substations, deferring forecast upgrades to both of these substations.

- Avondale – new 11kV feeder (2012)

Install a new 11kV feeder from Avondale substation to supply construction load at the south portal. NZTA is considering an alternative construction option using a 16MW 22kV Tunnel Boring Machine (TBM) at the south portal. The decision will be made in 2012/13. If this option proceeds a

22kV circuit will be required, supplied from 33kV rated switchboard to be installed at Avondale substation. Due to time constraints it has been decided to install a 33kV circuit between the south portal and Avondale, connected to a new 11kV circuit breaker at Avondale and operated at 11kV. If the TBM is the chosen option a new 33kV switchboard can be installed at Avondale and the 33kV circuit connected to the 22kV network. This connection provides the additional capacity needed to supply the TMB. Following completion of the construction works the 33kV cable and/or switchboard will be used to replace the Chevalier sub-transmission circuit on retirement of the existing 22kV cables from Kingsland (refer to project Chevalier 22kV PILC cables replacement below).

- Te Atatu – north portal permanent supply (2016)

  NZTA have indicated they require 100% redundancy for each of the tunnel portal permanent power supplies. Further they require each supply from different GXPs. The south portal will be supplied from Transpower Roskill while the north portal will be supplied from Transpower Hepburn Rd or Henderson via Te Atatu. From Te Atatu substation a new 33kV cable will be installed along the SH16 motorway in conjunction with planned widening activities. A 33/11kV substation will be established at the north portal.

  The 11kV feeders providing the construction supply to the north portal will be diverted to offload Mt Albert substation thereby deferring reinforcement of sub-transmission capacity at Mt Albert substation. Note that the Pt Chevalier construction supply to the north portal is unsuitable as a permanent supply as it is fed from Transpower Roskill, the same as the south portal.

- Sandringham – new 11kV feeder (2016)

  A new 11kV feeder from Sandringham substation will provide the permanent supply to the south portal. Note that the construction and permanent power supplies are needed at different locations for the south portal and the Sandringham supply offers a less costly option than extending the Avondale construction supply.

b. Projects – Within five to ten years

- Chevalier - 22kV PILC cables replacement

  A new 33kV switchboard will be installed at Avondale substation and 33kV cables will be extended through the Waterview tunnel from Avondale to Chevalier. The 33kV cable will replace the aged 22kV paper insulated lead cables (PILC) to Chevalier in due course. The timing of the replacement of PILC cables is condition-driven and the timing of the project year is provisional at this stage (see Section 6).

- Mt Albert - transformer replacement (2017)

  The existing 12MVA transformer at Mt Albert substation has been identified for condition-based replacement within the planning period (see Section 6). The replacement will be a 20MVA 33-22/11kV transformer to provide additional capacity while acknowledging the future planned upgrade of Roskill sub-transmission to 33kV. The timing for the transformer replacement is provisional at this stage.

- Mt Albert sub-transmission cables replacement (2020)

  Install a new 33kV circuit from Sandringham substation to Mt Albert substation to increase the capacity of Mt Albert substation.

A number of alternative options were investigated particularly around Waterview tunnel supply options. For the south portal these included:

- Establishing a new substation taking supply from Roskill GXP;
- Establishing a new substation taking supply from Sandringham substation 22kV;
- Installing a new 33kV feeder from Sandringham substation, operated at 11kV to initially supply the construction load, and then uprated to 22kV to supply the permanent load once construction is completed. The 33kV rated conductors are to ensure Roskill GXP may be uprated to 33kV in the future;
- Installing a new 11kV feeder from White Swan substation to the south portal; and
- Installing an 11kV feeder from Mt Albert substation to supply the south portal construction load.

For the north portal the options included:

- Installing a new 22kV feeder from Chevalier substation to the north portal; and
- Upgrading existing Chevalier 22kV PILC cables along the existing route.

Each of these options was evaluated and was either technically, or capital inefficient or failed to meet customer requirements, compared with the option proposed.

5.12.6 Roskill 22kV Sub-transmission Network

5.12.6.1 Background

Zone substations included in this group are Avondale, Balmoral, Hillsborough, Mt Albert, Sandringham and White Swan. Table 5-24 shows the summer and winter load forecasts at the GXP.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Roskill 22kV	141	65	76	78	80	82	88	89	90	91	91	92	93
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Roskill 22kV	141	104	117	118	119	120	125	126	126	127	128	129	130

Table 5-24 : Summer and winter load forecasts at Roskill 22kV group GX

5.12.6.2 Projects Planned

a. Projects – Within the next five years

- Avondale – new 11kV feeder for Waterview tunnel construction supply (2012)

  A new 11kV feeder from Avondale substation to the southern end of the Waterview tunnel to provide a construction supply. Refer to the Waterview project discussion in Section 5.12.5.2 above for details.

- Balmoral – new 11kV feeder to St Lukes (2014)

  A new 11kV feeder is proposed to be installed from Balmoral substation to supply additional load arising from expansion of the St Lukes Shopping Mall. This is a customer driven project with timing set by the customer.

- Sandringham – new 11kV feeder for Waterview tunnel permanent supply (2016)

  An 11kV new feeder will be installed from Sandringham substation for Waterview tunnel for the permanent supply to the south portal in 2016. Refer to the Waterview project discussion in Section 5.12.5.2 above for details.

- Avondale – new 33kV board

  A 33kV board is proposed to be installed at Avondale substation for the purpose of supplying Chevalier substation when Chevalier sub-transmission PILC cables are replaced. Refer to the discussion under the Kingsland Group (Section 5.12.5.2) for details.

b. Projects – Within five to ten years

- Avondale – two new 11kV feeders (2019)

  Two new 11kV feeders will be installed from Avondale substation in 2019. The new feeders are required to relieve heavily loaded Avondale feeders 1, 9 and 13.

- Hillsborough – 2nd transformer and 33kV circuit (2014)

  A second transformer and 33kV circuit will be installed at Hillsborough substation to enhance address forecast security issues at this substation in 2014.

- Hillsborough – New 11kV feeder (2021)

  A new 11kV feeder will be installed from Hillsborough substation to offload Onehunga substation in 2021.

- Mt Albert – transformer replacement (2017)

  Mt Albert transformer is proposed to be replaced in 2017.

- Mt Albert – sub-transmission circuit replacement (2020)

  Mt Albert sub-transmission circuit is proposed to be replaced in 2020.

5.13 Albany GXP

5.13.1 Albany Sub-transmission Network

5.13.1.1 Background

Vector takes supply from the Albany 33kV bus via three 220/33kV, 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 234/234MVA and eleven zone substations are supplied from this 33kV bus, namely, Coatesville, Waimauku, Bush Rd, James St, Forrest Hill, Sunset Rd, East Coast Rd, Mckinnon, Browns Bay, Waiake and Torbay. The summer and winter load forecasts are listed in Table 5-25.

Additional substations will be required in the future at Albany, Rosedale, Glenvar, Northcross and Albany Heights.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 33kV	234	109	118	122	126	130	134	136	138	141	143	145	147
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 33kV	234	151	156	158	160	163	165	167	169	171	174	176	178

Table 5-25 : Summer and winter load forecasts at Albany 33kV sub-transmission network

The geo-schematic diagram in Figure 5-18 shows the proposed supply arrangement in the Albany and Wairau areas.

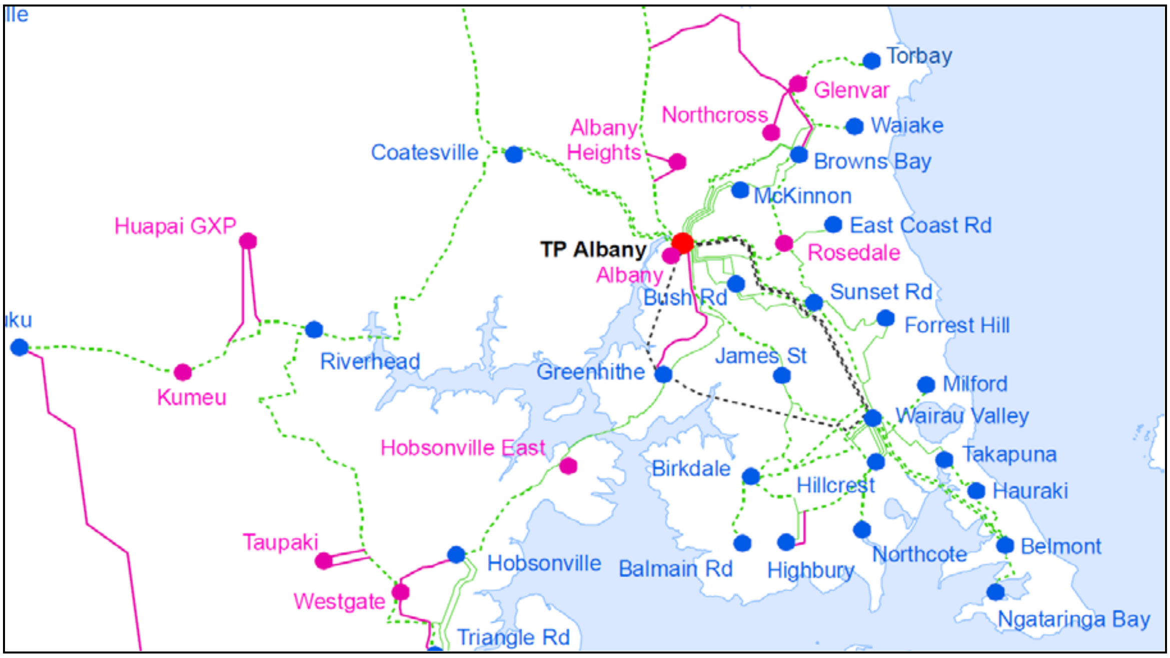


Figure 5-18 : Existing and proposed supply arrangement in the Albany and Wairau areas

5.13.1.2 Projects Planned

a. Projects – Within the next five years

- Rosedale substation (2012)

  The area around Rosedale Road, between the motorway and East Coast Road, has developed rapidly over the last five years. The bulk of this area is business zoned land. The 11kV feeders supplying this area are approaching capacity and need augmenting to provide sufficient backstopping capability. Additional capacity is required as there is still further land for development.

  The two recommended options from the list below were a new zone substation with a single 33/11kV transformer at Rosedale or a second 33/11kV transformer at East Coast Road substation. Both of these options would reinforce the area but the Rosedale option has the additional benefits of being able to backstop and offload Bush Road and McKinnon substations.

  The land for the substation will be purchased during 2011, while construction is set to start in 2012.

The following options were investigated:

- Establish a new zone substation on Auckland Council reserve land in Rosedale Road. This site provides the ability to interconnect with Bush Road and McKinnon substations and backstop these adjacent substations. It can also backup both East Coast Road and Sunset Road substations;
- Increase the capacity at East Coast Road substation. This option is practical but a second 33kV supply is required to provide security of supply to the substation. This can be achieved with a cable from Rosedale Road about 1.5km away but would require a 33kV switching station by the motorway. The cost difference between establishing Rosedale substation and reinforcing East Coast Road substation is minimal. However, reinforcing East Coast Rd substation places the network capacity on the edge of the load centre, rather than the centre as in the case of Rosedale substation. Therefore, the Rosedale substation is the preferred option;
- Use load control to reduce the load on the feeders. A large proportion of the load supplied in the Rosedale area is business load which has very little controllable load, such as hot water load. Commercial options are not currently in place and realistically are unlikely to be able to defer the proposed substation; and
- Transfer load to adjacent substations. This is not a realistic option without increasing the capacity of adjacent substations. McKinnon and Bush Rd are unsuitable for expansion at this time.

- Waimauku substation (2012)

Waimauku substation is a rural substation and has a single 7.5MVA 33/11kV transformer which is loaded to more than 80%. There is a single 33kV line supplying the substation from Riverhead. Further residential subdivisions are planned for the Waimauku area and reinforcement is required.

The proposed solution at this stage is to install a second 33/11kV transformer at Waimauku. This will provide adequate capacity and enable Waimauku to be able to backup Helensville substation in emergencies. A separate project will be initiated to install additional 11kV feeders.

The following options were investigated:

- **Transfer load:** There are few options available for transferring load. The closest substation is Riverhead which has two 7.5MVA transformers and a load of 9.6MVA. The distance between the two substations is 8.5km. To benefit, the new feeder would have to connect the two substations. This is a costly option with a cabled feeder costing around $2.5 million. An overhead feeder would have to be double circuit on existing poles, which has reduced reliability and is vulnerable to outside influences such as a car verses pole (as is the 33kV supply). This option is not a cost effective option;
- **Install a second transformer at Waimauku:** The plan is to install a second transformer at Waimauku. The additional transformer capacity will address immediate capacity constraints, but in the longer-term a duplicate 33kV supply from Swanson is needed to repair the security issues. The existing 33kV supply is quite reliable and it is planned to defer the second 33kV line until Waitakere substation is commissioned in 2019. The ex-Titirangi 10MVA transformer is to be used at Waimauku. This option resolves the

issues at Waimauku for some years and has the added benefit of increasing the backstopping to Helensville substation;

- **Install a larger transformer:** It would be possible to replace the existing 7.5MVA transformer with a larger transformer, such as a 12.5MVA unit. The switchgear is limited to 15.2MVA. This would resolve the capacity problem at the substation but a second transformer and a second 33kV line would still be required to mitigate security issues; and
- **Non-network options:** Non-network options which potentially may resolve the loading constraints on the Waimauku substation are still being investigated.

- Stapleford Crescent 11kV feeder (2012)

  This project has been initiated to transfer load from Torbay substation to Browns Bay substation. This option is a cost effective way of deferring the zone substation at Glenvar Rd.

- Mckinnon - the Avenue 11kV feeder (2013)

  The Avenue feeder is supplied from Mckinnon substation in the Albany basin. The Avenue feeder contains a spur line with 12 transformers. This area is still developing with new residential subdivisions and this project is required to provide a backstop to this feeder by connecting through to the Redvale feeder from Silverdale.

- Glenvar substation (2015)

  This project, originally planned for 2010, has been deferred by offloading Torbay substation onto Browns Bay substation. A new feeder will be installed from Browns Bay substation during 2011.

  Torbay substation has a single 33/11kV transformer and the transformer is more than 80% loaded. A shortfall of 4MVA of load cannot be backstopped upon the loss of the transformer. New subdivisions are planned to the north of Torbay substation which will add a further 7.5MVA of load. Reinforcement of the area is required.

  The proposed solution at this stage is to install a new 11kV feeder from Browns Bay and defer a new zone substation at Glenvar until the load at the Long Bay subdivision grows sufficiently to warrant reinforcement. Glenvar substation has the advantage of being able to offload Torbay substation, supply part of the new subdivisions at Long Bay and also reinforce to the west and north where further load growth is expected.

  The following options were investigated:

  - Install a second transformer at Torbay. This is a feasible option and would provide capacity for the proposed new subdivision. However, it is expensive and has limited benefits for the rest of the network;
  - Establish a new zone substation at Glenvar with a single 33/11kV transformer. This option offloads Torbay substation, supplies part of Long Bay subdivision and can supply new developments to the west of East Coast Road. It is planned to reinforce the 33kV supply to the area as part of this option which provides a backup supply to the Browns Bay 33kV bus;
  - Load control. Tests were carried out to determine how much load can be shed using the pilot network for turning off hot water supplies. There are limitations as to how much and how long the hot water supplies can be cut. Whilst load control is useful to control load

during network contingencies it is not a long-term solution to the anticipated load growth.

b. Projects – Within five to ten years

- Coatesville – Second Transformer (2018)

  A second 33/11kV transformer (10MVA) is planned for Coatesville substation. The existing transformer has sufficient capacity but the 11kV backstop security shortfall increases to an unacceptable level over this period.

- Waimauku 33kV line (2019).

  A new 33kV line will be installed from Swanson to Waimauku substation to provide a 33kV backstop to Waimauku substation. This will occur when the Waitakere substation is commissioned.

5.14 Wairau GXP

5.14.1 Background

Supply to Wairau zone substation is taken from Albany GXP at 110kV. The N-1 capacity limit (winter/summer) of this GXP is 143/143MVA and eleven zone substations are supplied from this 33kV bus, viz., Ngataringa Bay, Northcote, Highbury, Balmain, Birkdale, Milford, Wairau Valley, Takapuna, Hauraki, Belmont and Hillcrest. At Wairau there are two 110/33kV 36/45/80MVA transformers and one 110/33kV 45/80MVA transformer. The 110kV supply consists of a single circuit overhead line via the suburbs of Greenhithe, Glenfield, Marlborough and Wairau Valley rated at 82MVA (summer) and a double circuit overhead line taking a different route via the suburbs of Albany, Meadowood, Forrest Hill, and the Wairau Valley.

Each of these two circuits has a summer rating of 62MVA. The three transformers can each operate at a cyclic rating of 80MVA which provides a firm 160MVA capacity for N-1 transformer contingencies. Load has been shifted to the 33kV bus at Albany, reducing the load on the 33kV bus at Wairau to 130MVA in anticipation of the construction of a GXP at Wairau Rd. Once built, the firm capacity will be 200MVA and mitigate the HILP risk of the double circuit 110kV line failure. The forecast 110kV load is shown in Table 5-26.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 110kV	143	82	87	89	91	94	96	97	98	99	100	101	102
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 110kV	143	130	137	138	139	141	142	143	145	146	147	149	150

Table 5-26 : Wairau 110kV summer and winter load forecasts

The proposed GXP will consist of a single 220/33kV 120MVA transformer which will be supplied from a 220kV cable between Penrose and Albany that will be diverted to 220kV switchgear at Wairau. The GXP transformer can be supplied from either Penrose (via Hobson) or from Albany.

The ultimate load over the long-term, beyond this planning period, is expected to be 240MVA (three 120MVA transformers).

5.14.2 Wairau Road Sub-transmission Network

5.14.2.1 Background

The areas around Takapuna and Devonport are supplied by four zone substations via three 33kV circuits from Wairau 110/33kV substation. The three circuits form a ring supply to achieve better security of supply to the Takapuna commercial centre.

The main developments are occurring in the area supplied from Wairaua Smales Farm and the adjacent North Shore Hospital site. Some high rise developments have occurred at Takapuna and it is expected that Takapuna substation will need a second transformer within the next five years as the load continues to grow and Takapuna needs to offload adjacent substations such as Hillcrest.

The summer and winter load forecasts are listed in Table 5-27.

Name	Capacity	Actual load 2010	Forecast - Summer MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 110kV	143	82	87	89	91	94	96	97	98	99	100	101	102

Name	Capacity	Actual load 2010	Forecast - Winter MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Albany 110kV	143	130	137	138	139	141	142	143	145	146	147	149	150

Table 5-27 : Summer and winter load forecasts at Wairau Road substation

Following the upgrade of the 33kV lines between Wairau and Albany via James Street, James Street substation is now supplied from Albany substation and backed up from Wairau.

A project has recently been implemented to improve the security of supply on the Wairau to Birkdale 33kV circuits. This involved supplying Balmain substation from a new 33kV CB at Birkdale. It is planned to operate the three 33kV circuits in parallel to improve the security of supply to the area and reduce SAIDI. This requires some analysis on load sharing and protection issues before being implemented. A second project is planned to install a second transformer at Highbury and this may affect how the 33kV network is configured.

5.14.2.2 Projects Planned

a. Projects – Within the next five years

- Highbury – second transformer (2013)

  It is planned to install a second transformer at Highbury substation to reinforce the 11kV network in the Highbury, Birkenhead, Northcote and Birkdale areas. The area is supplied by Birkdale, Balmain, Highbury and Northcote substations. The Birkdale substation is fully developed. Options investigated include a second transformer at Highbury, Balmain or Northcote substations or a new zone substation.

  The load on Highbury is such that the ability to backstop is becoming an issue and would exceed Vector's security criteria in the next few years. Reinforcing Highbury would allow this substation to offload the adjacent substations of Balmain and Northcote and minimise the costs of reinforcement to the area.

  A new 11kV feeder will be installed as part of this project to offload the Birkenhead feeder from Northcote substation. Northcote substation has an 11kV backstop shortfall and the new feeder will resolve this issue.

- Belmont – new 11kV feeder (2014)

  The 11kV backstopping for Ngataringa Bay substation is inadequate and reinforcement is required. Ngataringa Bay substation supplies the Devonport area around the Naval Base and has a single 12.5MVA transformer. The area was reinforced in 2004 from Belmont substation with a new 11kV feeder and additional capacity is now required.

  Reinforcement of Devonport is not easy given the geographical features of the area. There is only one main road and one side road into Devonport. The existing 33kV supply to Ngataringa Bay substation is across the bay using a submarine cable. Several options are being investigated for the reinforcement:

  - Install a new 11kV cable from Belmont substation. This could be via the existing road network or across Ngataringa Bay with a submarine cable;
  - Ngataringa Bay substation could be reinforced with a second transformer; or
  - Generation could be installed at Ngataringa Bay.

  At this stage it is assumed that a new 11kV cable will be installed from Belmont substation which has sufficient capacity to supply the whole of the Ngataringa Bay substation load.

b. Projects – Within five to ten years

- Takapuna – second transformer (2018)

  The load at Takapuna and the surrounding area is expected to continue to grow. Various options were investigated but installing a second transformer at Takapuna, including three 11kV feeders to offload surrounding substations, is considered to be the most cost effective solution to reinforcing the area.

5.15 Hepburn Road GXP

5.15.1 Hepburn Road Sub-transmission Network

5.15.1.1 Background

Vector takes supply from the Hepburn 33kV bus via three 110/33kV transformers, 2x120MVA and 1x100MVA transformer. The N-1 capacity limit (winter/summer) of this GXP is 245/239MVA and ten zone substations are supplied from this 33kV bus, viz, Brickworks, New Lynn, Atkinson Rd, Laingholm, Oratia, Waikaukau, Henderson Valley, Keeling Rd, McLeod Rd and Sabulite as well as Rosebank in the Southern network. Additional future substations will be required at Titirangi and Green Bay.

The summer and winter load forecasts are listed in Table 5-28.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Hepburn	239	87	93	95	98	100	103	104	105	106	107	109	109
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Hepburn	245	117	119	120	121	122	124	125	126	127	128	130	131

Table 5-28 : Summer and winter load forecasts at Hepburn Road 33kV sub-transmission network

The geo-schematic diagram in Figure 5-19 shows the proposed supply arrangement in the Hepburn area.

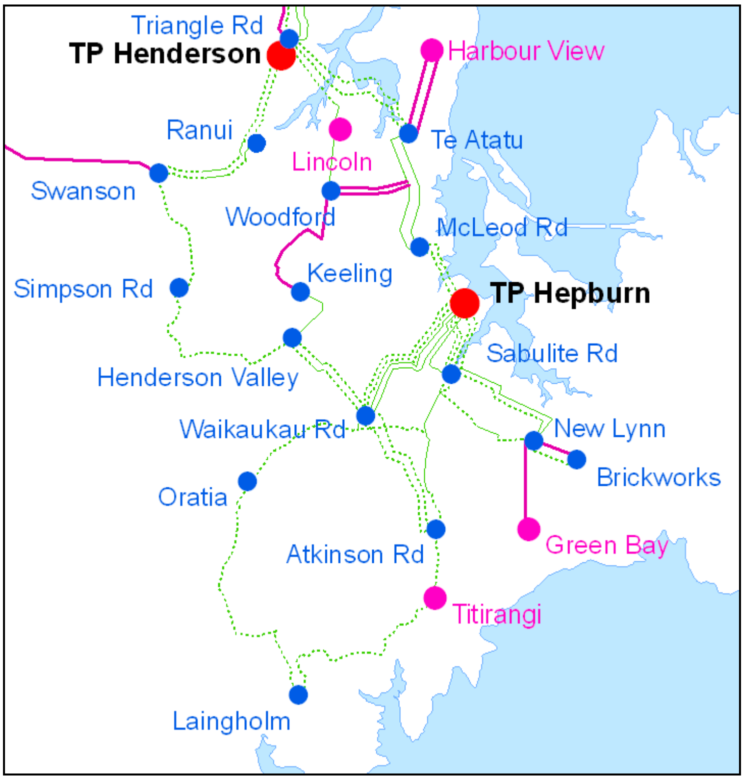


Figure 5-19 : Existing and proposed supply arrangement in the Hepburn area

5.15.1.2 Projects Planned

a. Projects – Within the next five years

- Keeling Road - Valley Road 11kV feeder reinforcement (2011)

  The Valley Road feeder is currently supplied from Henderson Valley zone substation. This feeder is quite heavily loaded, especially in summer, and requires offloading.

  It is proposed to install two new 11kV feeders from Keeling Road zone substation. This would enable the Valley Road feeder to be cut and turned into Keeling Road substation. This would effectively split the feeder into two and transfer the load from Henderson Valley to Keeling Road substation.

  Options include installing a new 11kV feeder from Henderson Valley substation, replacing undersized 11kV cable to increase the rating of the feeder or installing additional feeders from Keeling Road. Keeling Road substation was designed to take some of the Henderson Valley load as it is closer to the load centre.

- Atkinson Rd – new 11kV feeder (2015).

  A new 11kV feeder is planned out of Atkinson Rd substation. This substation is in the process of being redeveloped with larger 33/11kV transformers. It is planned to use the additional capacity from this substation to reinforce the 11kV network (Kaurilands feeder) and also offload the Waikaukau substation.

b. Projects – Within five to ten years

- Brickworks – second transformer (2016)

  Brickworks substation currently has a single 33/11kV transformer and the substation has been offloaded to Avondale substation to reduce the load. The area adjacent to the substation is now being developed as a high density residential subdivision (1,500 dwellings) with an expected load increase of around 4MVA. In addition, a new business load is being planned close to the substation which is around 3MVA. These additional loads mean a second 33/11kV transformer will be required for Brickworks substation to maintain the security of supply to the area. Brickworks substation is in poor condition and is planned to be redeveloped – refer to Section 6 for details. A new 11kV feeder is planned as part of this project to supply the load of the new subdivision.

- Rosebank North – new zone substation (2017)

  A new zone substation is planned to supply the northern part of the Rosebank peninsula. A 33kV cable will be laid as part of the works for the SH16 motorway upgrade.

- Oratia – new 11kV feeder (2018)

  The existing 11kV feeder supplying Piha is heavily loaded and requires reinforcement. Oratia substation has been recently commissioned and is physically closer to Piha. A new feeder to reinforce Piha from Oratia substation is planned.

- Keeling Rd – second transformer (2021)

  Keeling Rd substation is currently supplied by a single 33kV supply. As the load grows a second 33kV supply is planned, using an additional 33/11kV transformer.

5.15.2 Henderson Sub-transmission Networks

5.15.2.1 Background

Vector takes supply from the Henderson 33kV bus via two 220/33kV 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 135/135MVA and nine zone substations are supplied from this 33kV bus, viz., Triangle Rd, Ranui, Swanson, Woodford, Hobsonville, Te Atatu, Riverhead, Greenhithe and Simpson Rd.

The summer and winter load forecasts are listed in Table 5-29.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Henderson	135	76	78	80	83	85	88	89	90	92	93	94	95
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Henderson	135	95	100	101	103	104	105	107	108	109	111	112	113

Table 5-29 : Summer and winter load forecasts at Henderson 33kV sub-transmission network

Ranui substation has recently been commissioned. Additional substations will be required at Westgate in 2014, Waitakere in 2019 and Hobsonville East in 2019. Land in the Hobsonville area has recently been rezoned allowing more intense development. In addition, new substations will also be required for the Waterview tunnel north portal (2016) and Rosebank North (2017).

In the long-term, it is planned to establish a new GXP at Huapai to supply part of the area currently supplied from Henderson. As well as the three substations mentioned above, new substations will also be required at Taupaki and Harbour View.

The geo-schematic diagram in Figure 5-20 shows the proposed supply arrangement in the Henderson area.

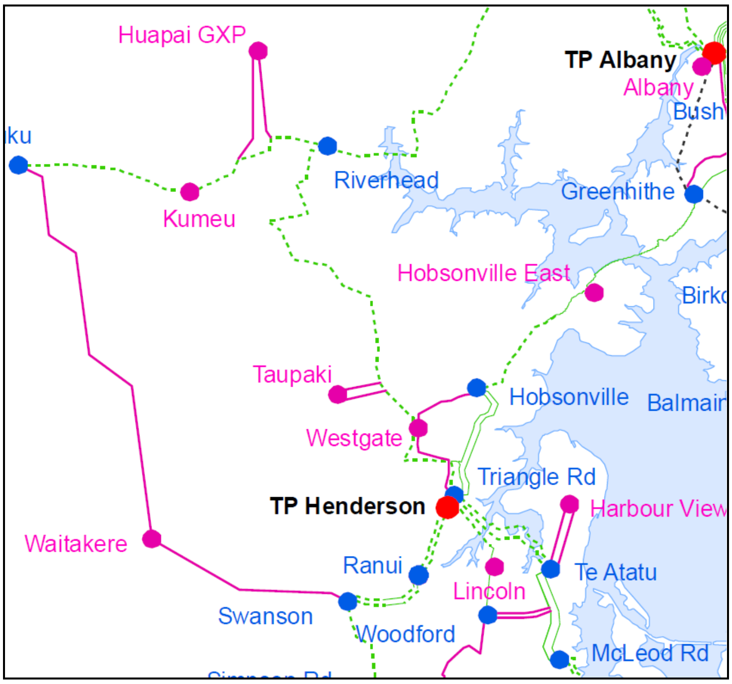


Figure 5-20 : Existing and proposed supply arrangement in the Henderson area

5.15.2.2 Projects Planned

a. Projects – Within the next five years

- Westgate Land Purchase (2011)

  The Massey North area has recently had the zoning changed to allow for the commercial and residential development to be expanded significantly. The existing substations supplying the area are getting heavily loaded and additional capacity is required to supply the new load.

  The currently preferred solution is to establish a new zone substation at Westgate. This would allow the existing Hobsonville substation to supply load further to the east until the Hobsonville East substation is built. This project is to purchase land suitable for the new substation.

  The options for the reinforcement project include:

  - Increase the capacity at Hobsonville substation with larger transformers. While this is possible, the supply to the substation is limited by the 33kV cables. Given the large loads expected in this area, this would only be a short-term measure;
  - Increase the capacity at Triangle Rd substation. Whilst feasible, the load centre is several kilometres north of this substation, making 11kV reinforcement expensive. In addition, there is no space in the substation for additional 11kV CBs to supply new 11kV feeders; and
  - Establish a new substation at Westgate. This option has the advantage of having the new capacity at the load centre. It is proposed to interconnect the 33kV cables with Hobsonville substation,

so that the 33kV link to Greenhithe has sufficient capacity to supply both Hobsonville East substation and Greenhithe substation in emergencies.

Non-network solutions which may potentially resolve the capacity issues in this area are still under investigation.

- Hobsonville - New 11kV feeder (2012)

  The Oriel Ave feeder from Hobsonville supplies the Westgate shopping centre. The feeder is 90% loaded over the summer period and it is planned to install a new 11kV feeder (33kV rated) to offload the Oriel Ave feeder. The cable will be 33kV rated so that when the Westgate substation (refer above) is commissioned, the new feeder will form a 33kV link between Hobsonville and Westgate substations.

- Swanson - Birdwood Feeder Extension (2013)

  Swanson zone substation has recently been offloaded by the new commissioned Ranui substation. This substation still has spare capacity and it is planned to use this capacity to further offload Swanson substation. The Birdwood feeder from Swanson would be extended so part of it could offload the Bethells Road feeder and part of it could be supplied from Ranui substation. This would enable the Waitakere substation (mentioned below) to be deferred and also improve the backstopping to Swanson substation.

- Westgate zone substation (2014)

  This project is to establish new zone substation. This project is discussed in more detail above.

- Hobsonville – Clark Road 11kV feeder reinforcement (2014)

  Most of the Clark Road feeder was decommissioned when it was uprated to 33kV to supply Greenhithe substation. The area currently supplied by this feeder is supplied from the new Greenhithe zone substation. In the longer term, a new zone substation will be required at Hobsonville East to meet the demand of the Hobsonville development. However, to delay the need for this substation, a new underground Clark Road feeder will be re-established.

  The area between Westgate and Hobsonville Airbase has been rezoned to allow for commercial and residential development adjacent to the new Greenhithe motorway. This will be a substantial load increase and will not be able to be supplied from the Hobsonville zone substation.

- Hobsonville East Land Purchase (2014)

  The long-term plan indicates that a zone substation will eventually be required to supply the new load developing between the existing Hobsonville substation and Greenhithe substation. Currently Greenhithe substation is supplying across the Greenhithe bridge to the old Hobsonville airbase. As this area is redeveloped, additional capacity will be required and this will be supplied temporarily by the new Clark Rd feeder mentioned above. However, in the medium to long-term a new substation will be required and this project is to purchase some land for the new substation.

b. Projects – Within five to ten years

- Waitakere zone substation (2019)

  This project is to establish a new zone substation at Waitakere Village. The primary purpose of this new substation is to offload the Swanson zone substation and reinforce the Bethells Road 11kV feeder.

The main options investigated were:

- Install a second 33/11kV transformer at Swanson and install a new 11kV feeder to reinforce the Bethells Road feeder;
- Establish a new zone substation closer to the load centre; and
- Defer Waitakere substation by splitting the Bethells Rd feeder and further offload to Ranui substation.

- Hobsonville East – new substation (2019)

  The load forecasts indicate that a new zone substation is required at Hobsonville East.

- Te Atatu – new transformers (2017)

  The load forecasts indicate that new 20MVA 33/11kV transformers are required at Te Atatu substation to comply with Vector's security criteria.

- Woodford – additional transformer (2021)

  An additional 33/11kV transformer is planned for Woodford substation together with the associated 33kV switchgear and 33kV link to Keeling Road substation.

- Lincoln Rd – new substation (2020)

  Development occurring in the Lincoln Rd area indicates that a new substation will be required. This project is to purchase land for the new zone substation.

5.16 Silverdale GXP

5.16.1 Background

Vector takes supply from the Silverdale 33kV bus via two 220/33kV transformers, one rated at 100MVA and one rated at 120MVA. The N-1 capacity limit (winter/summer) of this GXP is 109/109MVA and six zone substations are supplied from this 33kV bus, viz., Orewa, Manly, Spur Rd, Gulf Harbour, Red Beach and Helensville.

The summer and winter load forecasts are listed in Table 5-30.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Silverdale	109	46	50	51	52	53	55	56	57	58	59	59	60
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Silverdale	109	71	72	73	74	75	76	77	78	79	80	81	82

Table 5-30 : Summer and winter load forecasts at Silverdale sub-transmission network

Red Beach substation was commissioned in December 2007 and Gulf Harbour in January 2009. There are several other zone substations planned to be supplied from this GXP. These are at Kaukapakapa, Wainui (Silverdale North) and Waiwera. The Kaukapakapa substation is planned for 2017 when security at Helensville is forecast to be breached. However, this assumes the Waimauku substation reinforcement project is commissioned before then. There are no firm plans for the Silverdale North (Wainui) substation at this stage but discussions are being held with the developers for a site. An area has been identified for the Waiwera substation but land has not been purchased.

The geo-schematic diagram in Figure 5-21 shows the proposed supply arrangement in the Silverdale area.

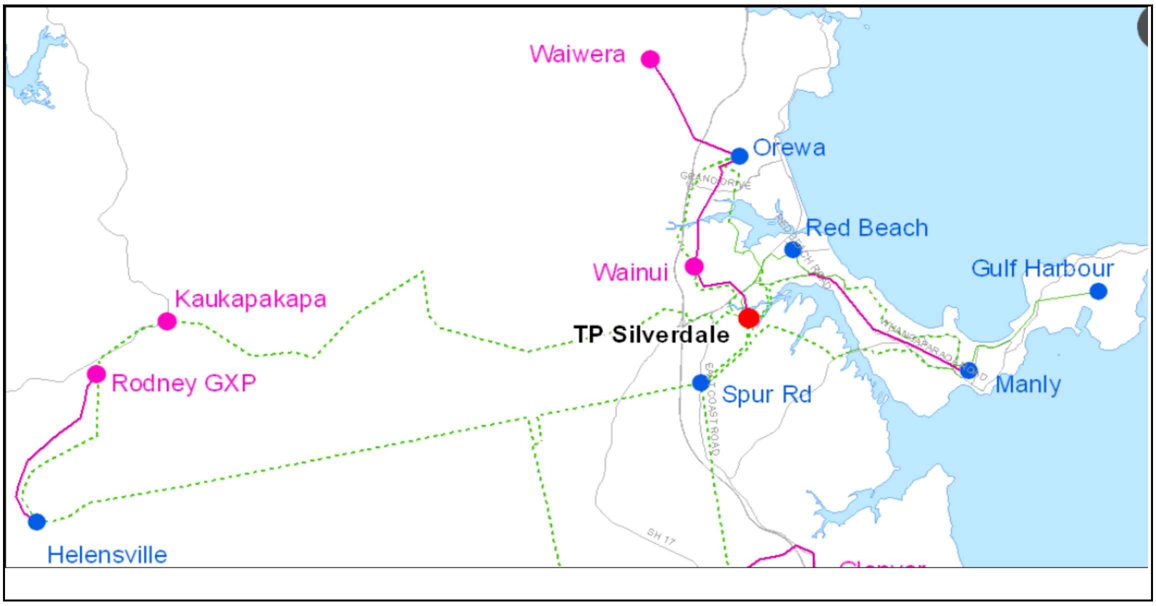


Figure 5-21 : Existing and proposed supply arrangement in the Silverdale area

5.16.1.1 Projects Planned

a. Projects – Within the next five years

- Orewa - Weranui 11kV feeder (2012)

  The Waiwera 11kV feeder from Orewa zone substation is a very long feeder supplying a largely rural area. The Hatfield 11kV feeder requires reinforcement and allows for future growth in the Waiwera area. Load flow analysis shows that over the next two to three years, the loads in both summer and winter will increase considerably. Any large loads proposed at Waiwera township and thermal area will be difficult to supply.

  The Waiwera feeder is constructed at 33kV for the first several kilometres and allows for a future zone substation. The plan is to underbuild the existing Waiwera feeder as far as Hillcrest Road and then split the feeder into two. This would provide immediate relief for the existing feeders and also allows for the future zone substation.

  Reinforcement options are very limited as the area is mainly rural with large areas of bush and the line runs across private property. Constructing a new line across private land would be difficult and there are no vested roads which can be used. This project has been delayed because of new subdivisions proposed along the line route and the need to co-ordinate the project with the subdivision programme.

- Red Beach – second 33/11kV transformer (2014)

  Red Beach substation was commissioned in 2007 with a single 33/11kV transformer. This substation has been able to offload the adjacent substations of Manly and Orewa and supply some of the new load coming on stream in the Silverdale North subdivision. The Silverdale North load is expected to grow over the next few years and by 2014 a second transformer will be required. This will allow this substation to continue to support Orewa substation and supply Silverdale North until the Wainui zone substation is commissioned.

- Orewa – Savoy 11kV feeder reinforcement (2015)

  The load forecast indicates that during this period, the Savoy and Maire Rd feeders will require reinforcement to comply with security criteria. It is expected that the northern end of the Silverdale North subdivision (Millwater) will develop quickly and would require additional capacity. A feeder cable has been previously laid a large part of the way and this project will take advantage of this cable.

- Wainui - substation land (2015)

  The long-term plan for the Silverdale area indicates that a new zone substation will be required at Silverdale North (Wainui), especially if the business park proceeds. This land is required to secure a site for the future zone substation. Load growth has been slower than expected and Red Beach can supply additional load once it gets reinforced with a second transformer. This land purchase will ensure that a new zone substation can be built in the future to reinforce Red Beach, Orewa and Spur Rd substations. Options considered include a second transformer at Spur Rd substation but this is too far from Silverdale North.

b. Projects – Within five to ten years

- Manly – Wade River feeder reinforcement (2016)

  The Wade River 11kV feeder from Spur Rd substation supplies across the Weiti River to close to Manly substation. This was done to offload Manly substation which was heavily loaded before it was reinforced from Red Beach and Gulf Harbour substations. It is now possible to install a new feeder from Manly to offload the Wade River feeder and restore the open points to a more normal configuration. The Pine Valley feeder from Spur Rd supplies the industrial area of Silverdale and requires offloading. The Wade River feeder can do this once it is offloaded onto Manly substation.

- Kaukapakapa – establish substation (2017)

  The load forecasts indicate that by 2017 a new zone substation will be required at Kaukapakapa to reinforce and offload Helensville substation.

5.17 Wellsford GXP

5.17.1 Background

Vector takes supply from the Wellsford 33kV bus via two 220/33kV 30MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 31/31MVA and three zone substations are supplied from this 33kV bus, viz., Wellsford, Warkworth and Snells Beach.

The summer and winter load forecasts are listed in Table 5-31.

Name	Capacity	Actual load 2010	Forecast - Summer MVA 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wellsford	31	21	22	23	23	24	25	25	25	26	26	26	27
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA 2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Wellsford	31	30	30	31	31	32	32	33	33	33	34	34	35

Table 5-31 : Summer and winter load forecasts at Wellsford sub-transmission network

There are no line CBs at Wellsford and a project is being investigated to replace the outdoor switchgear with indoor CBs. This would improve the security of supply from the substation.

Upon loss of any one of the two circuits between Wellsford substation and Warkworth substation at peak time, overloading is expected to occur on the remaining circuit. One option is that the Dog conductor in circuit 54E (9.7km) is upgraded immediately and the Cricket conductor in both the circuits (total 20.2km) be upgraded to Cockroach conductor later in 2011.

As the circuits are close together in places, there is also a risk of both circuits being taken out by the same event (common mode failure such as a tree falling over). A second option is to construct the third 33kV circuit from Wellsford to Warkworth (Whangaripo feeder).

There are three sites for future zone substations supplied from this GXP – one at Big Omaha (Leigh Road), one at Tomarata (opposite Domain) and one in Warkworth (Glenmore Drive). The site at Omaha South was bought some time ago and the load has developed further to the south at Matakana. It may be desirable to sell the Omaha South site and buy a new one at Matakana. This site would enable the new substation to be ring fed on the 33kV network and allow the 11kV feeders to easily integrate into the existing network.

There is planned growth in the Mangawhai Heads and Te Arai areas which may bring forward the Tomarata substation. Proposals for developing Te Arai have been scaled back and may not be such a significant load in future. Voltage drop on the 11kV network has been identified as a growing issue and additional 11kV voltage regulators and/or capacitor banks may be required.

A further substation will be required at Sandspit in 2015 to offload and backstop Snells Beach substation. The shortfall is worse in the summer. Options for a 33kV ring (Southern Ring) between Warkworth, Sandspit, Snells Beach, Glenmore Drive and back to Warkworth have been investigated and a preferred option selected, as indicated on the plan below. The third 33kV circuit from Wellsford to Warkworth will improve the security of supply to these substations.

Discussions have been held with Northpower about a 33kV link between Wellsford and their Mangawhai Heads substation but this may not proceed as it would be very expensive to install. A 33kV line will eventually be built to Tomarata for a new zone substation but this is still some years away and it is still some distance from Tomarata to Mangawhai. It is likely that Northpower will reinforce the area from the north.

The geo-schematic diagram in Figure 5-22 shows the proposed supply arrangement in the Wellsford area.

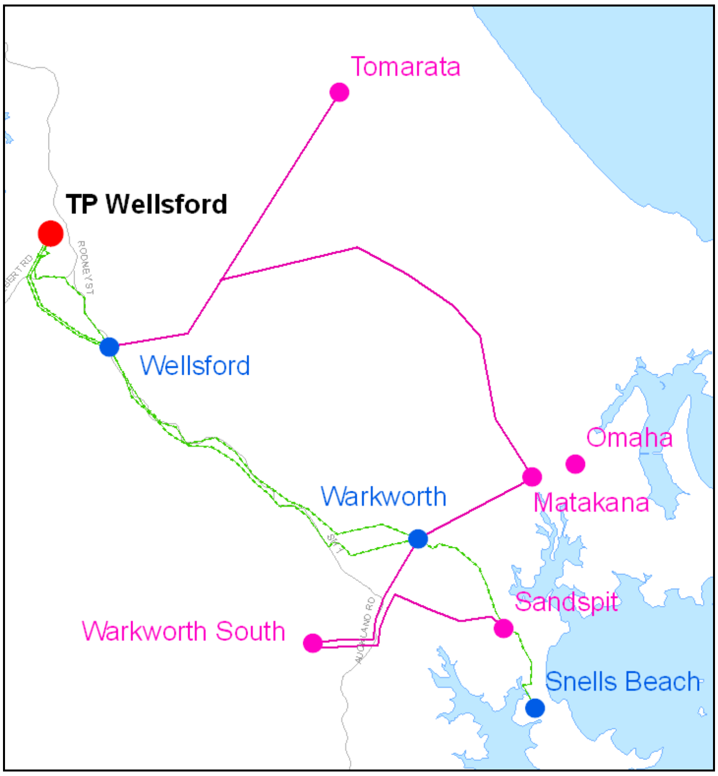


Figure 5-22 : Existing and proposed supply arrangement in the Wellsford area

5.17.1.1 Projects Planned

a. Projects – Within the next five years

- Warkworth - New 11kV feeder to reinforce the Warkworth industrial area (2012)

  The Woodcocks Rd area is the industrial heart of Warkworth and has been developing rapidly over the last few years. The two main feeders supplying this area (Woodcocks and Limeworks) are very heavily loaded and cannot be fully backstopped during peak load times. The long-term plan to reinforce this area is to establish a new zone substation in Glenmore Road. The existing Warkworth substation is about 5km away to the east and the available 11kV feeder capacity into this area is inadequate. This project is to install a new 33kV cable from Warkworth substation to Woodcocks Road and initially operate this new feeder at 11kV. This would provide temporary relief to the 11kV network until the zone substation is required. Given the forecast load for this area, non-network options are not economically viable.

- Warkworth - Matakana 11kV feeder reinforcement (2015)

  The Matakana 11kV feeder from Warkworth substation is a very long semi-rural feeder with limited backstopping. The load on this feeder is growing and it is proposed to offload this feeder. The first part of the Whangateau feeder was constructed at 33kV to allow for a future zone substation in the area. The proposed solution is a new 11kV feeder from Warkworth (underbuilt on an existing line) and a reconfiguration of the 11kV network to rebalance the loads.

- Sandspit – new zone substation (2015)

  The existing supply to the Sandspit and Snells Beach areas is from Snells Beach substation. This is a single transformer substation with a 7.5MVA transformer installed. The substation is currently about 80% loaded and will require reinforcement in the next few years. New subdivisions have been developed in this area and more are planned. There are two main reinforcement options. The first option is to reinforce the Snells Beach substation with a second transformer. The second option is to construct a new substation at Sandspit and this is the preferred option. This option would allow the Snells Beach load to be offloaded and backstopped with the 33kV supply forming part of the southern 33kV ring including the future Warkworth South substation.

- Warkworth South – new zone substation (2015)

  Warkworth zone substation was established about 5km to the east of Warkworth township. Over the years, Warkworth township has expanded to the west and east meaning the load centre has moved further from Warkworth substation. There are currently three 11kV feeders supplying this area and they are now in need of reinforcement (see new feeder planned for 2012). Warkworth substation switch room is fully extended and the long-term plan for supplying the Warkworth area is to establish new zone substations at Warkworth South (Glenmore Rd) and at Sandspit. The area is largely rural and has some very long feeders which means voltage regulation can be an issue. Establishing a new zone substation at Warkworth South will provide additional capacity at the load centre and enable some of the very long feeders to be offloaded and shortened.

b. Projects – Within the five to ten years

- Warkworth - Whangateau 11kV feeder reinforcement (2016)

  The Whangateau 11kV feeder from Warkworth substation is a very long semi-rural feeder with limited backstopping. The main backstop for this feeder is the Tomarata feeder from Wellsford and, during contingency events, low voltage is an issue. In conjunction with the Matakana feeder reinforcement project (see above) it is planned to install a backstop from Omaha Beach (which is supplied by a spur line) to the Whangateau feeder. This provides a backstop for Omaha Beach and also a backstop for the Whangateau feeder. Other options such as voltage regulators and capacitor banks will be investigated to see if they can solve any of the supply issues.

5.18 Pakuranga GXP

5.18.1 Background

Transpower's Pakuranga 33kV bus is supplied by two 110/33kV 120MVA transformers with an N-1 capacity limit of 136/136MVA (winter/summer). Five zone substations are supplied from Pakuranga including East Tamaki, Greenmount, Howick, Pakuranga and South Howick. The summer and winter load forecasts are listed in Table 5-32 and a layout of the sub-transmission arrangement from the GXP is shown in Figure 5-23.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pakuranga	136	104	108	108	111	114	116	119	121	123	125	127	129
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Pakuranga	136	130	131	132	134	135	137	138	140	141	143	144	146

Table 5-32 : Summer and winter load forecasts for Pakuranga 33kV sub-transmission network

The 2010 winter peak demand was 130MVA, just below the N-1 capacity limit.

Transpower is going to upgrade the existing 110kV grid to 220kV as part of the NIGUP. The two existing 110/33kV 120MVA transformers will be replaced with two 220/33kV 120MVA transformers by 2011. At the same time an additional 220/33kV 120MVA transformer will be installed to provide a firm 240MVA, N-1 capacity. This will meet the expected long-term capacity requirement.

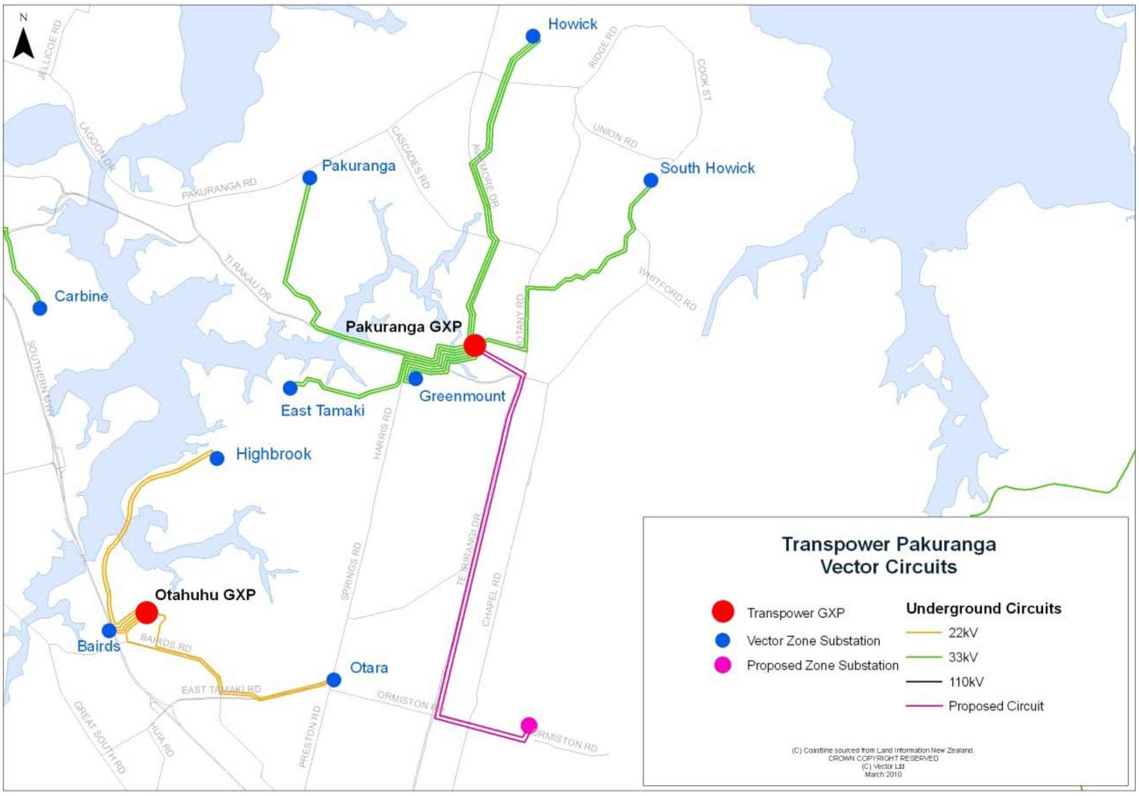


Figure 5-23 : Existing and proposed supply arrangement in the Pakuranga area

5.18.1.1 Projects Planned

a. Projects – Within the next five years

- Greenmount – 11kV feeder to Armoy Drive (2014)

  Install a new 11kV feeder from Greenmount substation to Armoy Drive. This feeder will be installed to provide security to Greenmount feeder 20 and Greenmount feeder 8.

b. Projects – Within five to ten years

- Flatbush zone substation (2018)

  Flat bush has been identified as a new town centre in Manukau. Currently this area is supplied from the Otara substation. Depending on the load growth Otara substation will not be able to meet the load requirement in Flatbush area by 2018. The area will be a major load centre and it is planned to have a zone substation in this centre. Two 20MVA transformers will be installed in this substation.

5.19 Otahuhu GXP

5.19.1 Background

Vector takes supply from the Otahuhu 22kV bus via two 220/22kV 50MVA transformers. The N-1 firm capacity limits (winter/summer) of this GXP is 59/59MVA. Two zone substations are supplied from this Otahuhu 22kV bus, viz., Bairds and Otara. The summer and winter load forecasts are listed in Table 5-33.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Otahuhu	59	47	46	48	50	53	55	57	59	61	63	66	68
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Otahuhu	59	56	57	57	59	61	63	65	67	69	72	74	77

Table 5-33 : Load forecasts at Otahuhu 22kV sub-transmission network

The 2010 peak demand at this GXP was 56MVA. It should be noted that the demand in the area covered by the GXP is also served by an embedded generation plant at Greenmount (typically generating 1.8MW). Taking this into account, the full peak load in the area in 2010 was 57.8MVA. The capacity of the two transformers is 100MVA, but its N-1 capacity is restricted due to 22kV incomer cable ratings. Addressing this issue will lift the N-1 capacity to 67/71MVA (summer/winter). The present load projection indicates that the demand on this GXP will exceed 59MVA (excluding generation) by 2014. Transpower has planned to remove the LV cable and bushing constraints on the transformers in 2011.

The geo-schematic diagram in Figure 5-24 shows the existing supply arrangement in the Otahuhu area.

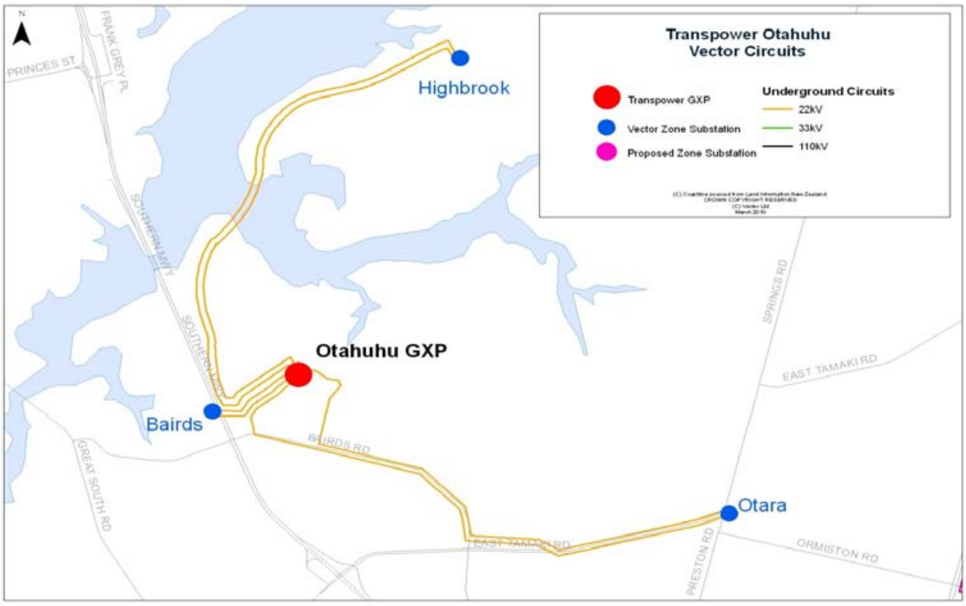


Figure 5-24 : Existing supply arrangement in the Otahuhu area

5.19.1.1 Projects Planned

a. Projects – Within the next five years

- Otara – new 11kV feeder along Ormiston Road (2013)

  Load is growing in Ormiston Rd and a new 11kV feeder is required. This feeder will be installed to provide security to Otara feeders 2, 5 and 7. Further, this new feeder will supply new load in the Flatbush area.

- Otara – new 11kV feeder to Chapel Rd (2015)

  Flat bush is a fast growing area in Manukau, supplied from Otara substation mainly by two feeders Otara 5 and 7. Even after installing a new feeder to reinforce these two feeders, depending on load growth we may require another feeder from Otara substation to this area to meet demand.

5.20 Mangere GXP

5.20.1 Background

Vector takes supply from the Mangere 33kV bus via two 110/33kV 120MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 118/118MVA and five zone substations are supplied from this Mangere 33kV bus, viz., Auckland Airport, Hans, Mangere Central, Mangere East and Mangere West. The summer and winter load forecasts are listed in Table 5-34.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Mangere	118	84	89	93	96	100	104	107	111	115	119	122	125
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Mangere	118	95	98	101	104	107	110	113	117	121	124	127	129

Table 5-34 : Summer and winter load forecasts at Mangere 33kV sub-transmission network

The 2010 winter peak demand was 95MVA. This load is projected to increase to 129MVA towards the end of the planning period. The large increase is mainly due to the anticipated development of the area surrounding Auckland Airport. Vector also supplies a major customer (Pacific Steel) directly from the 110kV bus. The winter peak load will exceed the transformers' N-1 capacity in 2018.

Transpower has a project to investigate removing the protection and equipment limits on the supply transformers. This will raise the N-1 limit to 138/143MVA (summer/winter). The capacity required at saturation for this GXP is 214MVA.

The geo-schematic diagram in Figure 5-25 shows the existing supply arrangement in the Mangere area.

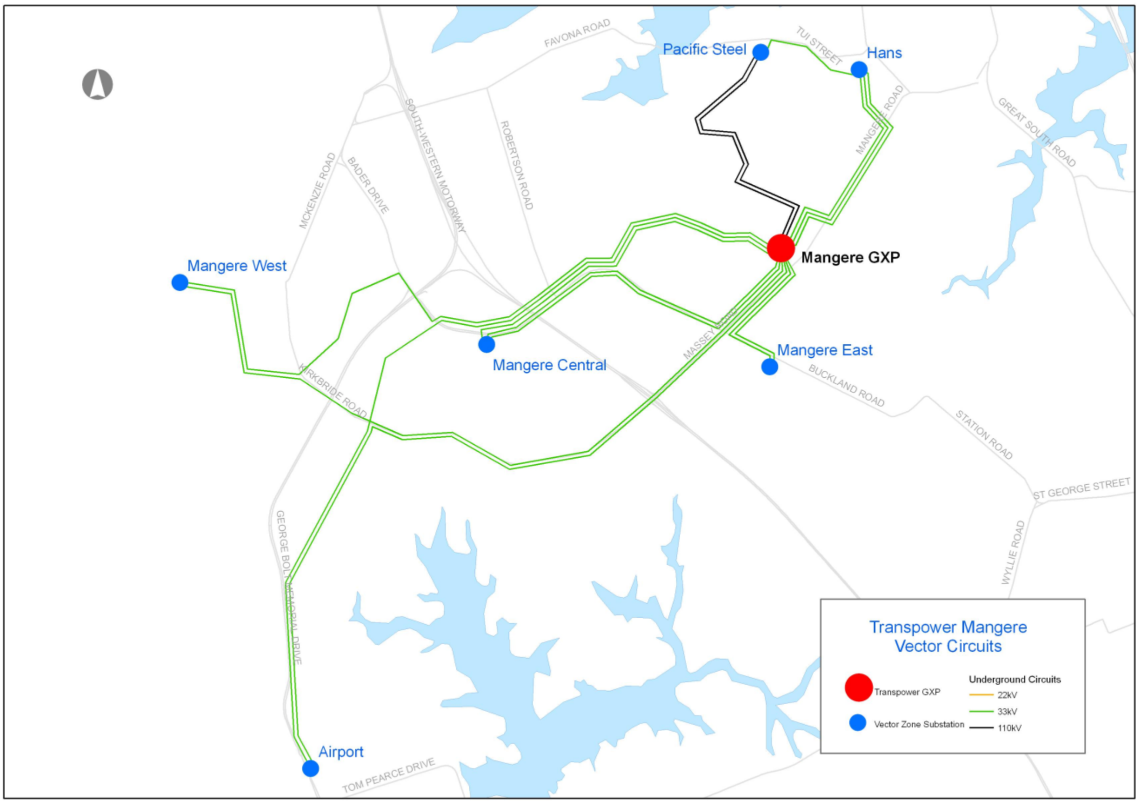


Figure 5-25 : Existing supply arrangement in the Mangere area

5.20.1.1 Projects Planned

a. Projects – Within the next five years

- Mangere West – Extend Mangere West feeder 2 (2015)

  Extend the Mangere West feeder 2 to provide security to the Mangere central substation. This project will provide security to Mangere Central feeders 5 and 18.

5.21 Wiri Sub-transmission GXP

5.21.1 Background

There are two 110/33kV 50/100MVA transformers installed at this GXP. The 110kV supply to this GXP is obtained via a tee off from the two Bombay to Otahuhu 110kV lines. The capacity to Wiri is limited by the capacity of these 110kV lines and how they are operated. The N-1 capacity limits (winter/summer) of this GXP are 92/101MVA and three zone substations are supplied from this Wiri 33kV bus, viz., Manukau, Wiri and Clendon. The summer and winter load forecasts are listed in Table 5-35.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wiri	92	72	73	75	77	80	83	85	87	89	91	94	96
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wiri	101	75	76	78	80	82	84	86	88	90	92	94	96

Table 5-35 : Summer and winter load forecasts for Wiri 33kV sub-transmission network

The 2010 winter peak demand was 75MVA. The present load projection indicates the demand on this GXP will exceed the capacity by winter 2020.

Transpower is considering the following options to increase capacity:

- A third circuit from Otahuhu to Wiri, either an overhead line or an underground cable – a third supply transformer would be installed at Wiri and the existing Wiri T1 replaced with a 120MVA unit;
- An increase in the capacity of the 110kV Otahuhu to Wiri circuits by replacing the existing conductor with conductor of a higher rating - the two existing transformers would be replaced with two 240MVA supply transformers; and
- Create a new 220kV GXP under the Huntly to Otahuhu A line east of Wiri, and supply Wiri from that point via 33kV cables. This option would include re-conductoring the Otahuhu-Wiri circuits and eventually replacing Wiri T1 with a 120MVA unit.

The geo-schematic diagram in Figure 5-26 shows the existing supply arrangement in the Wiri area.

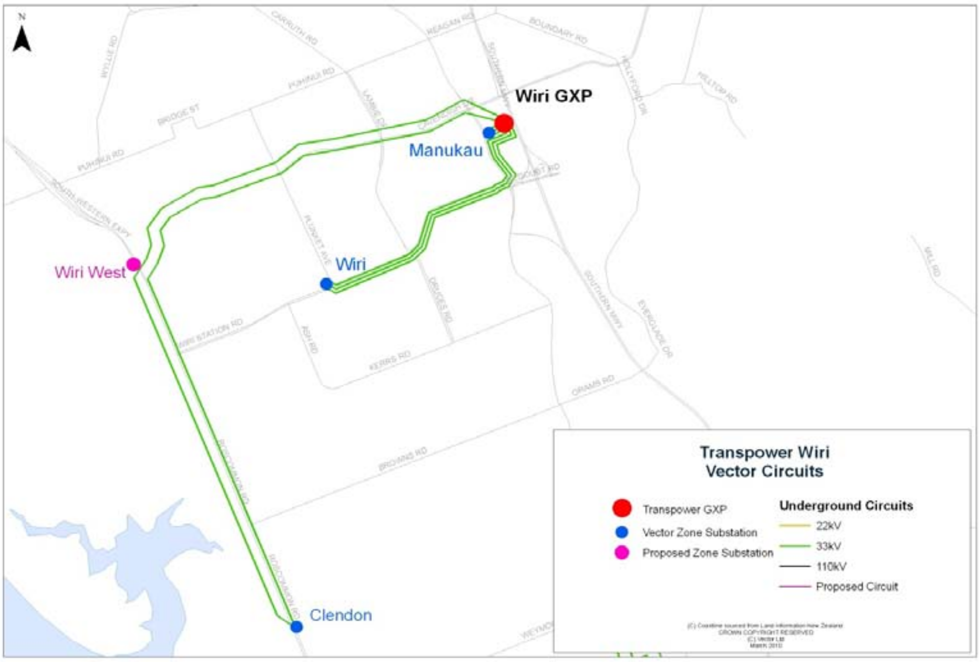


Figure 5-26 : Supply arrangement in the Wiri area

No major projects are planned in the AMP planning period in this area.

5.22 Takanini GXP

5.22.1 Background

Vector takes supply from the Takanini 33kV bus via two 220/33kV 150MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 123/123MVA and six zone substations are supplied from this Takanini 33kV bus, viz., Takanini, Manurewa, Papakura, Clevedon, Maraetai and Waiheke. Table 5-36 shows the summer and winter load forecasts at the GXP.

Name	Capacity	Actual load 2010	Forecast - Summer MVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Takanini	123	87	85	88	91	93	96	98	100	101	103	105	106
Name	**Capacity**	**Actual load 2010**	**Forecast - Winter MVA**										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Takanini	123	113	115	117	118	120	122	123	124	126	128	129	130

Table 5-36 : Summer and winter load forecasts at the Takanini GXP

The winter load reduction at Takanini is due to load transfer to Wiri, made possible by the commissioning of Clendon substation in late 2009.

The two 220/33kV 150MVA transformers installed at this GXP have 123/123MVA (winter/summer) N-1 capacity limits. This capacity is limited by a protection constraint. The 2010 peak demand was 113MVA. The projected demand at this GXP is expected to reach 130MVA towards the end of the planning period. The 220kV supply to this GXP is via a tee off from the two Glenbrook to Otahuhu 220kV circuits.

The winter peak load is expected to exceed the transformers' N-1 capacity in 2017. The transformers' capacity is presently limited by protection equipment limit, circuit breaker (137 MVA) and 33 kV bus (137 MVA) limits; with these limits resolved the N-1 capacity would be 188/198 MVA (summer/winter). Transpower has plans to resolve these issues by 2015.

The geo-schematic diagram in Figure 5-27 shows the existing and proposed supply arrangement in the Takanini area.

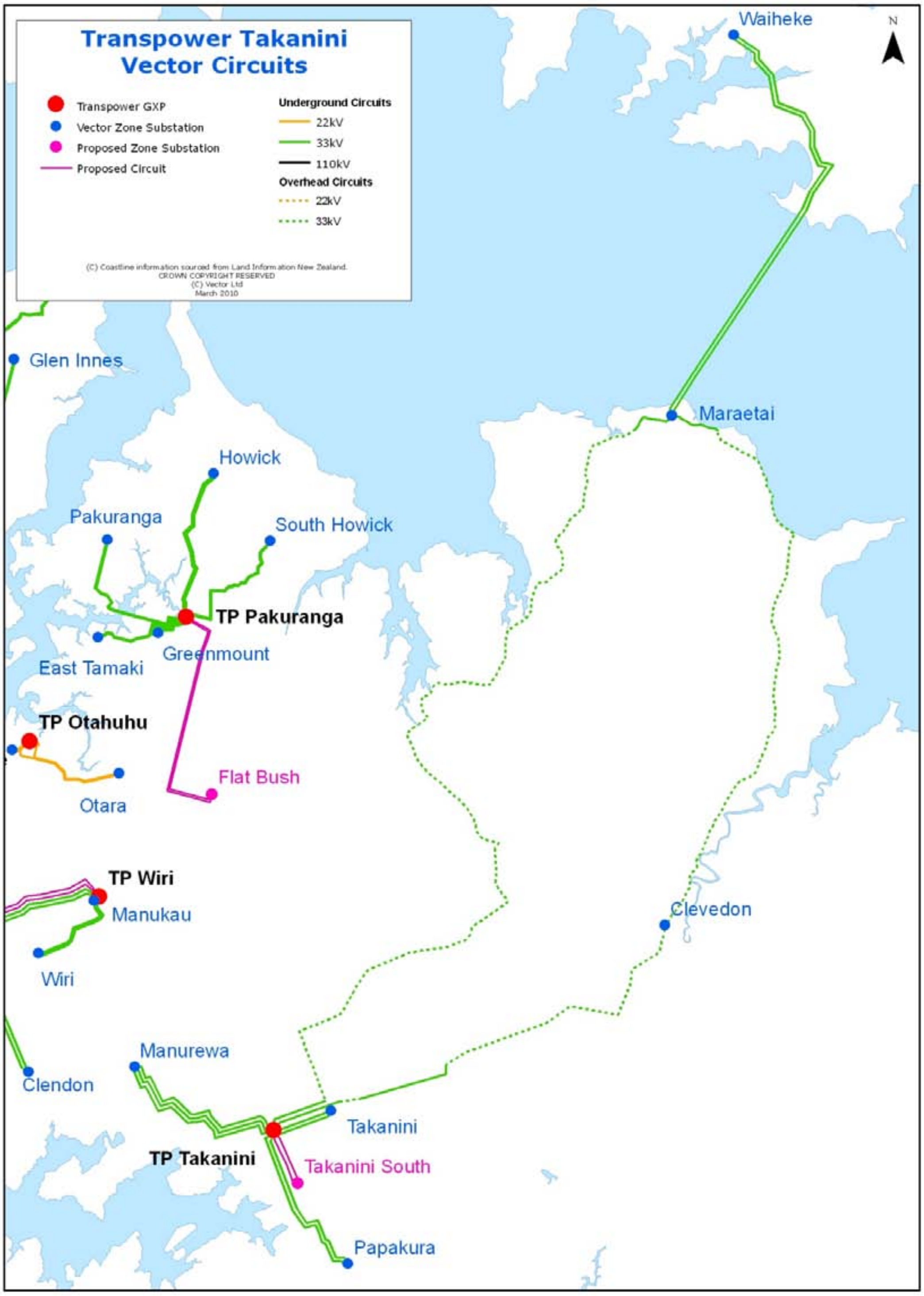


Figure 5-27 : Existing and proposed supply arrangement in the Takanini area

5.22.1.1 Projects Planned

a. Projects – Within the next five years

- Maraetai– new 11kV feeder to reinforce Maraetai feeder 9 (2012)

  A new 11kV feeder will be installed along Whitford Maraetai Road to provide security to Maraetai 9 feeder.

- Takanini– new Porchester Road feeder (2014)

  Takanini is another fast growing area in the south of Auckland. According to the load forecast another feeder is required to meet the demand in Takanini area by 2014. It is proposed to install a new 11kV feeder from Takanini zone substation to Porchester Road.

b. Projects – Within five to ten years

- Takanini– new 11kV feeder to Mill Road (2019)

  According to the load forecast another new feeder is required to meet the demand in the Takanini area in 2019 in addition to the feeder proposed for Porchester Road in 2013. It is proposed to install a new 11kV feeder from Takanini zone substation to Mill Road.

5.23 Asset Relocation

Vector's electricity network assets are required to be relocated to make way for work carried out by other infrastructure organisations (requiring authorities) or landowners. Infrastructure projects could be initiated by other utilities (such as Transpower and Telecom) or roading authorities such as the NZTA and local councils. Vector is obliged by law to relocate its assets when requested. The process and funding of such relocation work is governed by the Electricity Act and Transit Act.

The timing of these projects is driven by the authority concerned and generally without the level of advance notice or detailed scope normally associated with growth projects. Information about projects more than one year in advance is generally not available for all but the large multi-year projects. In this respect forecasts are based on continuation of the current level of relocation activity.

The relocations forecast is divided into two groups, namely the larger projects as described above and a second group comprising of the smaller projects such as pole relocations, minor network relocations, etc. The budget allocated to minor relocations has remained static over the last few years at $2.5 million per annum.

Following is a list of known large infrastructure projects that require relocation of Vector electricity network assets:

- KiwiRail has initiated a project to upgrade the Auckland rail network by providing double-tracking and electrification. Relocation of existing 11kV and LV cables is required at various railway crossing sites to either provide sufficient clearance for the railway works or to relocate assets that are in the passage of the widened rail corridor;
- NZTA widening of SH1 at Warkworth. This affects a number of intersections and lines and cables are being relocated;
- NZTA are extending the Greenhithe motorway from the new Greenhithe bridge to Westgate. Several intersections are affected and provision is being made for future 33kV and 11kV cabling as part of the works. This work is expected to continue over the next two to three years;
- NZTA is planning to widen the north-western motorway from Waterview through to Westgate;
- NZTA is constructing a tunnel between the harbour bridge motorway off ramp at Fanshawe Street and Victoria Park. Vector's existing 11kV and LV cables around Curran Road, Fanshawe Street/Beaumont Street intersection will need to be relocated. This is at the construction stage;

- NZTA plans to construct a tunnel between Waterview and Avondale. Existing 11kV and LV cables that impinge on the work area will need to be relocated. This project is at the planning stage;
- Auckland Transport is planning to upgrade and make improvements to CBD locations including Upper Khartoum Place, Elliott Street, Darby Street, Fort Street area and Lorne Street. This project is at the implementation stage;
- Auckland Transport has initiated a project to upgrade and improve roads and public transport facilities around Eden Park. The project is underway and will be completed before Rugby World Cup in 2011;
- Watercare has initiated a project to upgrade the water mains around Mt Wellington Quarry. Most works are being carried out in conjunction with the Mt Wellington Quarry subdivision development;
- Relocation of water mains at Lunn Avenue, Norman Lesser Drive and Ngahue Drive will be carried out and completed in mid 2011;
- Watercare proposes to install a new water main from Redoubt North Reservoir in Manukau to Market Road in Epsom. The project is at the proposal stage;
- Transpower has initiated a 400kV transmission line construction between Whakamaru to Browns Hill Road as part of the NIGUP and Vector is relocating its assets to make way for this line; and
- Auckland Transport is planning to upgrade the Flat Bush School Road/Murphy Road intersection. This project is in the planning stage.

5.23.1 Undergrounding of Overhead Lines

Vector, through an agreement with its majority shareholder, the Auckland Energy Consumer Trust (AECT)[45], commenced the Overhead Improvement Programme (OIP) in 2001. Through this it aims to underground or make improvements for amenity purpose to the remaining overhead electricity lines across the urban areas of the former Auckland City, Manukau City, and Papakura District.

Through the agreement Vector commenced the programme investing a minimum of $10 million per year on undergrounding in this area. The minimum amount of undergrounding is inflation-adjusted each year by the producer's price index (PPI). The minimum investment targeted for the 2009/2010 year is $12.5 million.

United Networks, when acquired by Vector in 2003, had embarked on an undergrounding programme in the areas of the former Rodney District, North Shore City, and Waitakere City. This programme was funded through dividends from shares in United Networks held through the Waitemata Electricity Trust for Rodney District Council, North Shore City Council, and Waitakere City Council. The United Networks Share Holders Society, as trustees of the Waitemata Electricity Trust, was responsible for administering payment for the undergrounding work.

With the councils divesting their United Networks shares through the sale of the company to Vector and then opting to use the proceeds of the sale of shares to fund other council activities, dividend income to the trust ceased. Vector continued with this programme until the available funds in the trust, approximately $11 million, had been invested through further undergrounding activity. Vector has not been able to justify further investment in the undergrounding of overhead lines across the areas of the former Rodney District, North Shore City, and Waitakere City since funding support from the Waitemata Electricity Trust ceased in 2005.

[45] This is a requirement of the Trust Deed.

5.23.1.1 Criteria for Selecting the Area for OIP

Vector sets its priority for undergrounding based on the condition and performance of overhead lines. Priority is given to undergrounding areas where large investments would otherwise be needed to rebuild overhead lines.

Secondary drivers include (a) the frequency of faults in the area (pole strikes, etc.), (b) the resulting benefit versus undergrounding costs, (c) the level of other council or utility works planned for the area, and (d) other synergy opportunities that help to reduce overall costs and provide other benefits.

5.23.1.2 Projected OIP Expenditure

Vector's targeted investment in undergrounding for the 2009/2010 year is $12.5 million. Projected expenditure for undergrounding over the next ten years will be targeted at the same (real) level but adjusted to reflect movements in PPI. The projected expenditure projection over the planning is shown in Table 5-37 below.

Financial Year	2010 /11	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20
Budget ($M)	12.7	15.6[46]	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

Table 5-37 : OIP improvement budget

5.24 Protection, Automation, Communication and Control

Vector's electricity distribution network has to continually evolve and adapt to changing customer requirements and technological developments. The challenges ahead include the requirement to integrate distributed energy resources into the distribution network, to assure improved resilience and quality of supply and to provide customers with increased flexibility to control their appliances and electricity consumption patterns, while still retaining a safe, economically and technically efficient electricity network.

We foresee that the power system of the future will:

- Be made up of numerous automated transmission and distribution systems, all operating in a coordinated, efficient and reliable manner;
- Handle emergency conditions with 'self-healing' actions and will be responsive to energy-market and utility business-enterprise needs; and
- Serve millions of customers and have an intelligent communications infrastructure enabling the timely, secure and adaptable information flow needed to provide reliable and economic power to the evolving digital economy.

To successfully address the challenges such a future power system poses, electricity distribution businesses need to develop not only their power networks, but also the information and control networks supporting this. Future network applications are likely to lead to continuously increasing network-complexity, necessitating incremental deployment and integration of more sophisticated protection and control equipment, widespread use of sensors and IED and improved information and communication technologies.

[46] Due to various factors, the targeted OIP programme in the 2010/11 financial year is unlikely to achieve the budgeted amount. The 2011/12 proposed budget has therefore been consequentially increased to make up the shortfall in the 2010/11 OIP programme.

Figure 5-28 and Figure 5-29 show the parallels between the power and information infrastructures that utilities have to manage.

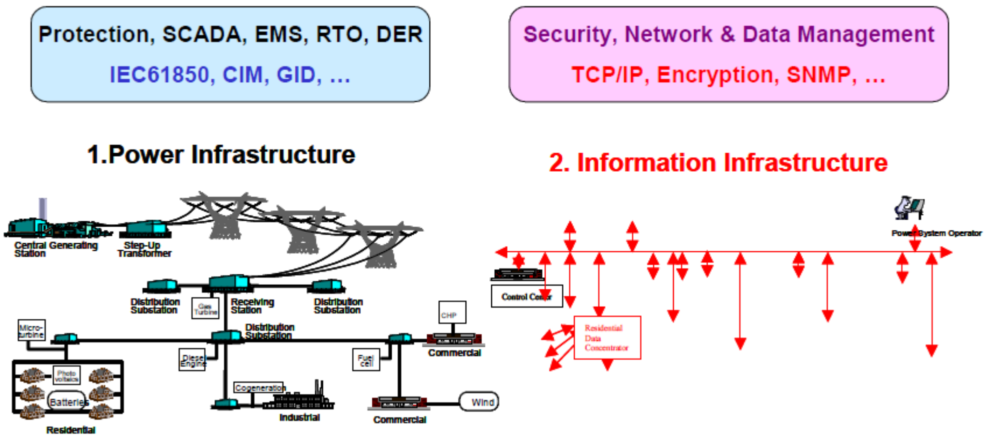


Figure 5-28 : Mirroring the power and information infrastructures at a utility

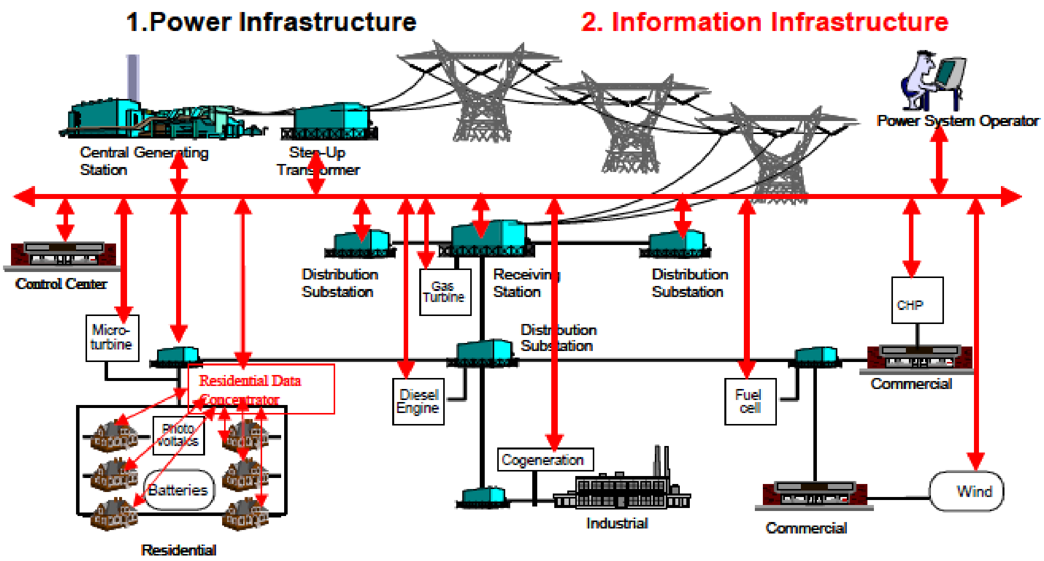


Figure 5-29 : Power system infrastructure with integrated information and communication systems

As the use and applications for "intelligent" control and information devices on electricity networks increase, the offering of equipment and solutions are increasing apace. This leads to a bewildering array of potential devices, standards, solutions and opportunities, some of which provide a high degree of flexibility and compatibility, but many of which rely on proprietary systems, effectively locking in the user.

Vector has decided to adopt, as far as practicable, a standard, internationally-recognised, open communications architecture, that would allow different devices and applications to integrate seamlessly and would allow Vector to choose from a wide range of present and future applications. Adoption of a standards based power system information infrastructure is considered vital to allow the required flexibility to ensure the ongoing, optimal development of our control systems. In Figure 5-30 the key standards adopted by Vector for its information and control systems are illustrated.

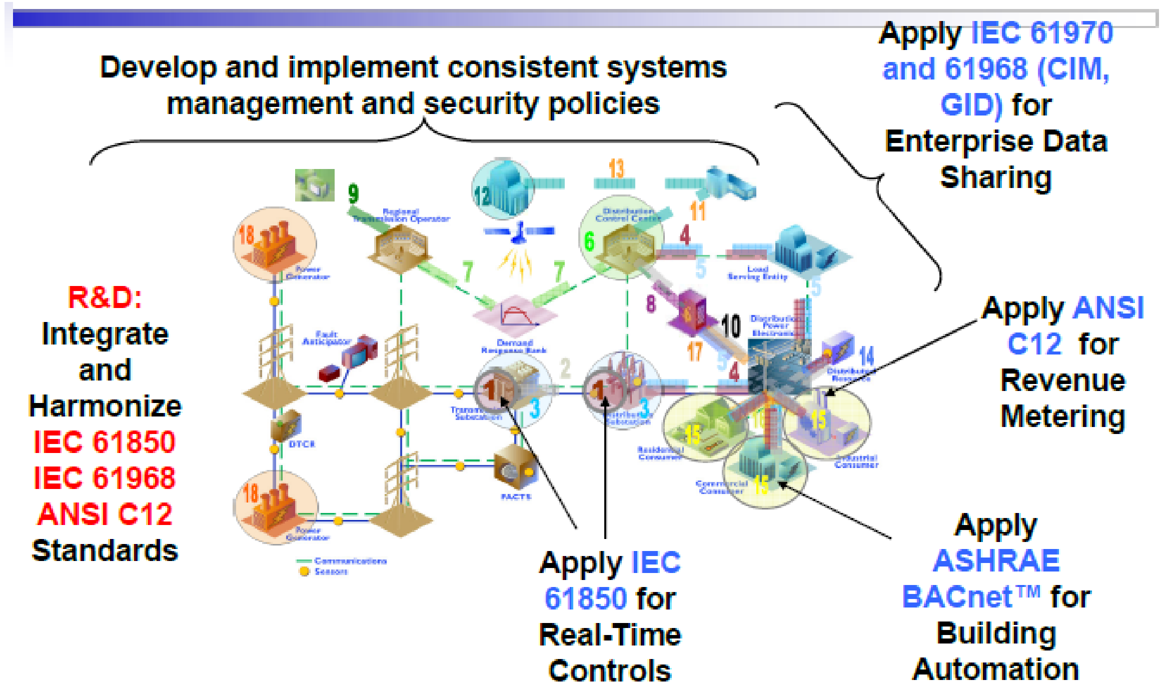


Figure 5-30 : Key standards for information and control systems

An approach that is independent of the architectural technology chosen is necessary to deal with the increased complexity of the power system and to facilitate systems interoperability and reduction in information integration costs.

The International Electrotechnical Commission (www.iec.ch) is the leading global organisation that prepares and publishes international standards for all electrical, electronic, and related technologies, primarily for the electric power industry. The IEC is spearheading a global initiative to support the new "smart" electric power network. IEC Technical Committee TC 57 (Power Systems Management and associated information exchange - http://tc57.iec.ch) has developed unique reference architecture for power system protection, automation, communications and control systems. Figure 5-31 shows the IEC TC57 reference architecture, which Vector has also adopted.

The reference architecture reflects the ultimate objectives for an information infrastructure that can meet all business needs, including network configuration requirements, quality of service requirements, security requirements, and data management and exchange requirements. It will enable integration of:

- Abstract modelling;
- Security management;
- Network and system management;
- Data management and exchange; and
- Integration and interoperability.

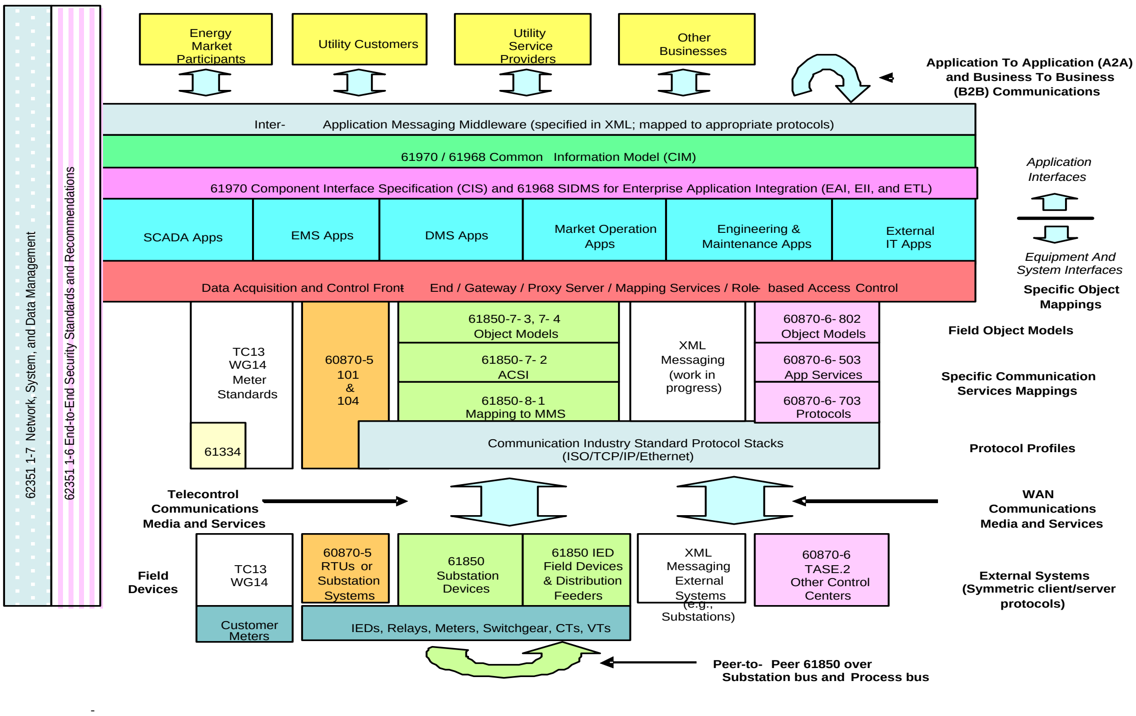


Figure 5-31 : IEC TC57 reference architecture

- Adopting this reference architecture facilitates:
- Innovation (enabling advanced applications that will require a ubiquitous infrastructure);
- Cost Efficiency –
    - Capital savings from standardised components that can be competitively procured;
    - Life cycle savings from lower maintenance costs due to standardisation;
    - Reduction in stranded assets from systems that can integrate;
    - Ability to incrementally build upon first steps; and then scale up massively; and
    - Reduced development costs by building on components of the reference architecture systems engineering;
- Resilience (achieved from structured approaches to systems management); and
- Increased security - consistently and adequately secure the energy industry.

5.24.1 Power System Protection

All of Vector's new and refurbished substations are equipped with multifunctional IEDs. Each IED combines protection, control, metering monitoring and automation functions within a single hardware platform. IED compliance to IEC 61850 is mandatory.

Vector's older protection system is being phased out over time, with the main drivers for this being:

- Protection system obsolescence (non-compliance with system requirements);
- End of technical life or unit failure;

- Reduced maintenance cost (cost efficiency);
- Improving safety;
- Improving reliability;
- Standardising and simplifying maintenance practice; and
- Standardising protection installation designs.

At present over 50% of Vector's primary substation are equipped with IEC 61850 compliant IEDs.

5.24.1.1 Network Protection – Design Standards

The main functions of a network protection system are to rapidly detect network faults by monitoring various parameters (current, voltage etc) and selectively initiate fault isolation should an abnormal situation be observed. As a result the protection system minimises damage to the electricity system components (generators, overhead lines, power cables, power transformers, CBs etc) and loss of supply to customers.

Protection systems take into account the following principles:

- Reliability - the ability of the protection to operate correctly;
- Speed - minimum operating time to clear a fault;
- Selectivity - disconnection of minimum network sections in order to isolate the fault; and
- Cost - maximum value from investments.

a. Maximum Fault Clearing Time

Maximum fault clearing time is defined as the time from fault initiation to the fault breaking device arc extinction. Main protection maximum fault clearing time is stipulated in Table 5-38.

Fault Location	System Voltage			
Primary Equipment	**11kV**	**22kV**	**33kV**	**110kV**
Switchgear and Power Transformer Faults	150ms	150ms	150ms	150ms
Line Faults	600ms	150ms	150ms	150ms

Table 5-38 : Maximum fault clearing time

The fault clearing time of the back-up protection shall not exceed the short-circuit thermal withstand capability of the primary equipment.

b. Protection Schemes

Vector's primary network equipment is protected to minimise damage during any type of faults. All new and refurbished substations are equipped with multifunctional IEDs. Each IED combines protection, control, metering monitoring, and automation functions within a single hardware platform. It also communicates with the substation computer or directly to SCADA central computers over the IP based communication network using industry standard communication protocols.

c. Line Protection

Table 5-40 sets out the protection schemes for protecting the various parts of the distribution network.

Line Type	System Voltage	Protection Scheme
Overhead Line	110k	Main - Longitudinal Differential protection (ANSI 87L) Back-up - Distance Protection (ANSI 27) - Breaker Failure (ANSI 50BF)
Overhead Line	33 / 22kV	Main - Longitudinal Differential protection (ANSI 87L) Back-up - Over-current and Earth Fault (50 /51)
Overhead Line	11kV	Main - Over-current and Earth Fault (50 /51) Back-up - Over-current and Earth Fault (50 /51)
Underground Cable	110kV	Main - Longitudinal Differential protection (ANSI 87L) - Thermal overload (ANSI 49) Back-up - Distance Protection (ANSI 27) - Breaker Failure (ANSI 50BF)
Underground Cable	33kV / 22kV	Main - Longitudinal Differential protection (ANSI 87L) - Thermal overload (ANSI 49) Back-up - Over-current and Earth Fault (50 /51-50N/51N)
Underground Cable	11kV	Main - Over-current and Earth Fault (50 /51) Back-up - Over-current and Earth Fault (50 /51)

Table 5-39 : Line protection schemes

Dedicated optical fibres are used for all communication assisted protection schemes eg. longitudinal differential protection scheme.

a. Auto Reclosing

Auto-reclosing is applied to overhead network but not to the underground cable or combined underground cable and overhead lines.

b. Busbar Protection

Table 5-40 sets out the protection schemes for protection busbars at zone substations and bulk supply substations.

System Voltage	Protection Scheme
110kV	Main - Low Impedance differential protection (ANSI 87BB) Back-up - Over-current-time and Earth Fault (ANSI 50/51-50N/51N)

System Voltage	Protection Scheme
33, 22 and 11kV GIS	Main - Arc detection (50AR) or Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV AIS – Metal-clad	Main - Arc detection (50AR) or Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV AIS	Main - Low Impedance differential protection (ANSI 87BB) Back-up - Over-current and Earth Fault (ANSI 50/51-50N/51N)

Table 5-40 : Busbar protection schemes

5.24.2 Control Centre Applications

5.24.2.1 SCADA Master Station

Two main SCADA master station applications are presently used for remote control and data acquisition on Vector's electricity network:

- Siemens Spectrum Power TG; and
- LN2068 with Foxboro Workstations.
- A Siemens Spectrum Power TG master station has been deployed for monitoring and control of the Southern region electricity networks, while LN2068 is used for the Northern region. Vector's modern substation automation system and other field IEDs installed in recent years have been, and continue to be, interfaced to both SCADA master stations, enabling a migration process of Northern SCADA information into PowerTG. Once migration is completed, the LN2068 system will be retired.

As with the rest of the Vector information system topology, SCADA solutions based on non-proprietary industry open standards are applied. This is a major driver for flexibility and cost efficiency. Vector has standardised on the Power TG application since 2002 but, as a legacy of acquiring UnitedNetwork Limited in 2002, inherited another SCADA system comprising components (LN 2068 master station application, RTU) that supports legacy Conitel 2020/2025 communication protocol and customised add-on applications. The system and most of its components are now obsolete, labour intensive, inefficient and costly to incorporate into Vector's modern open standard based substation and distribution automation solutions. Future-proofing of the legacy system is also problematic.

Vector has, therefore, adopted a long-term strategy for the complete migration of the Northern region real-time information to the Siemens Spectrum Power TG system, to allow us to operate one, efficient SCADA system and to standardise in our applications. The migration process started in 2004 and the intended integration solution is shown in Figure 5-32. The project is underway to complete the migration and decommission LN 2068, due for completion in 2011.

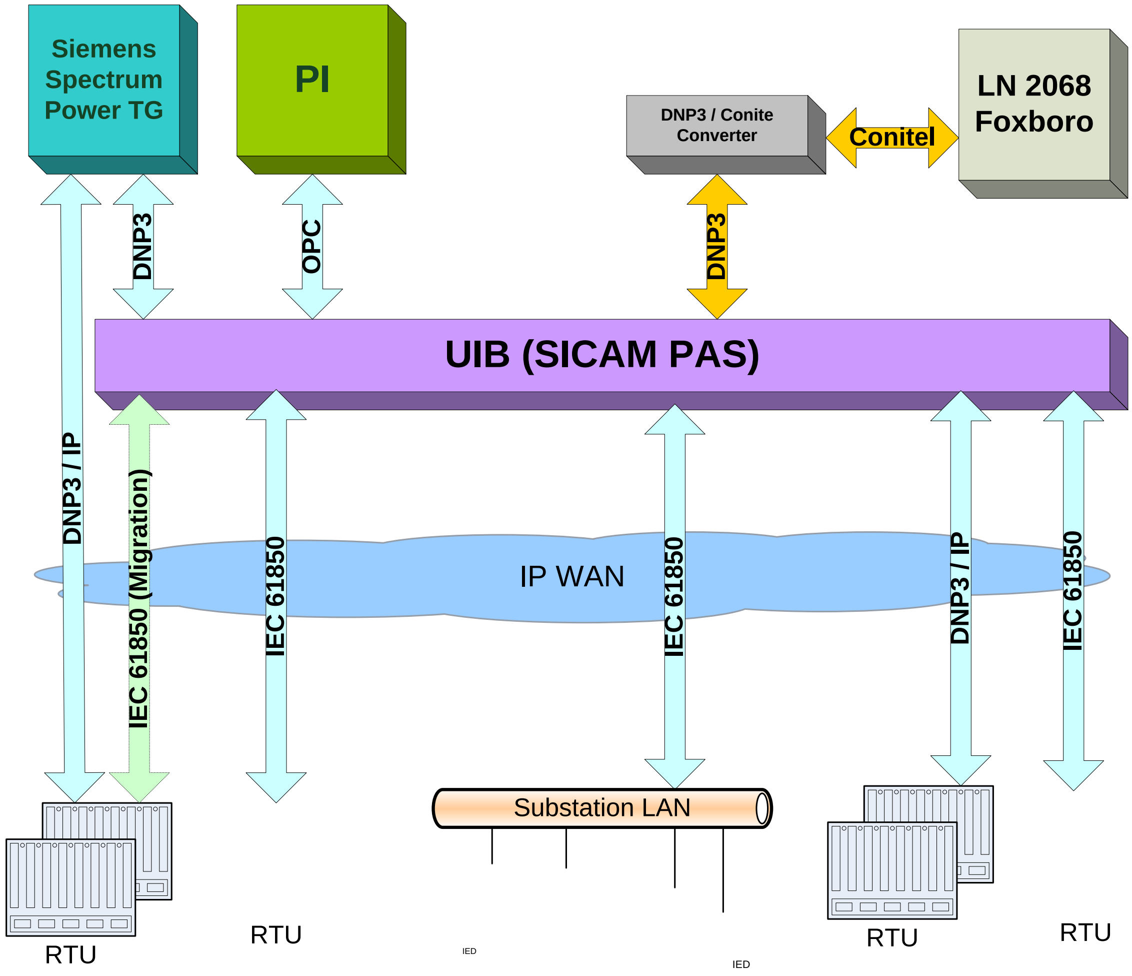


Figure 5-32 : The field information integration solution to the Control Centre applications

5.24.2.2 Future SCADA Spectrum Power TG Vision and Development

Siemens is a leader in the implementation of IEC 61850 based solutions, which is the standard adopted by Vector. Siemens has a number of sophisticated SCADA system products and it has laid out its vision and evolutionary path towards a unified platform compliant to the recommended standards (IEC 61850 and IEC61970 CIM), as shown in Figure 5-33, Figure 5-34 and Figure 5-34. This is aligned with Vector's SCADA and information system strategy and we are in the process of upgrading the application upgrade to Power TG V8.3.

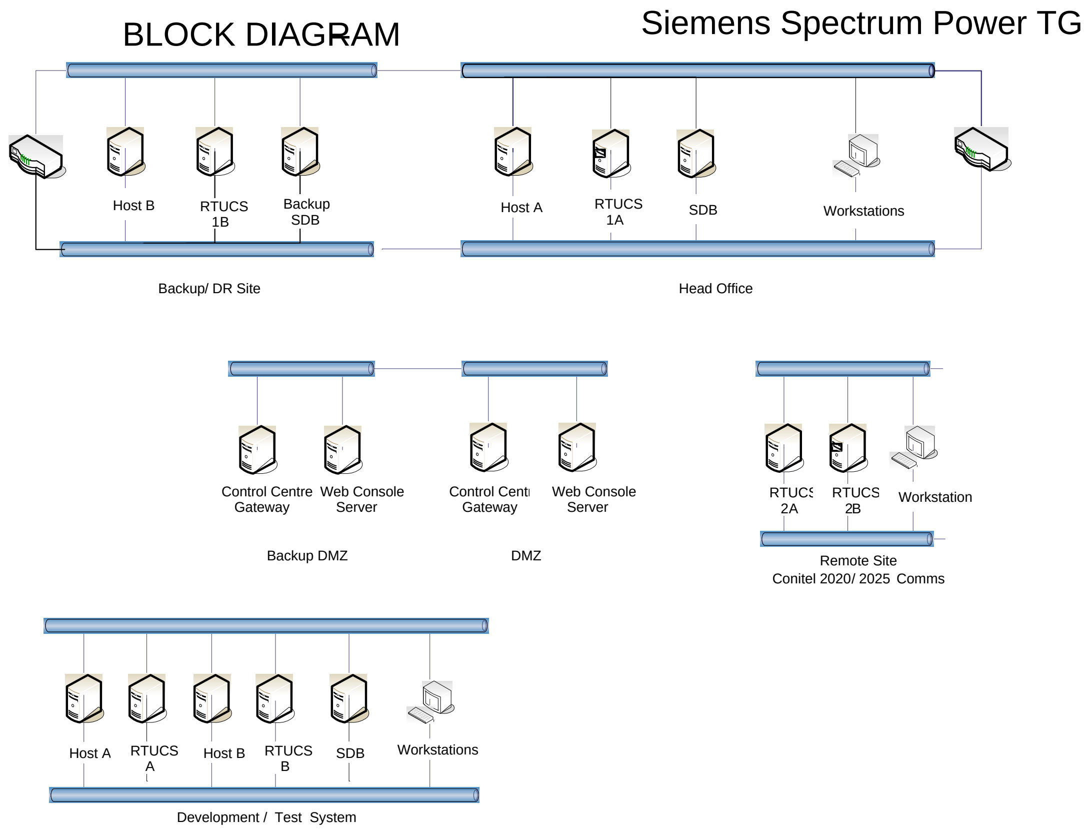


Figure 5-33 : Siemens Spectrum Power TG Master Station Application Architecture

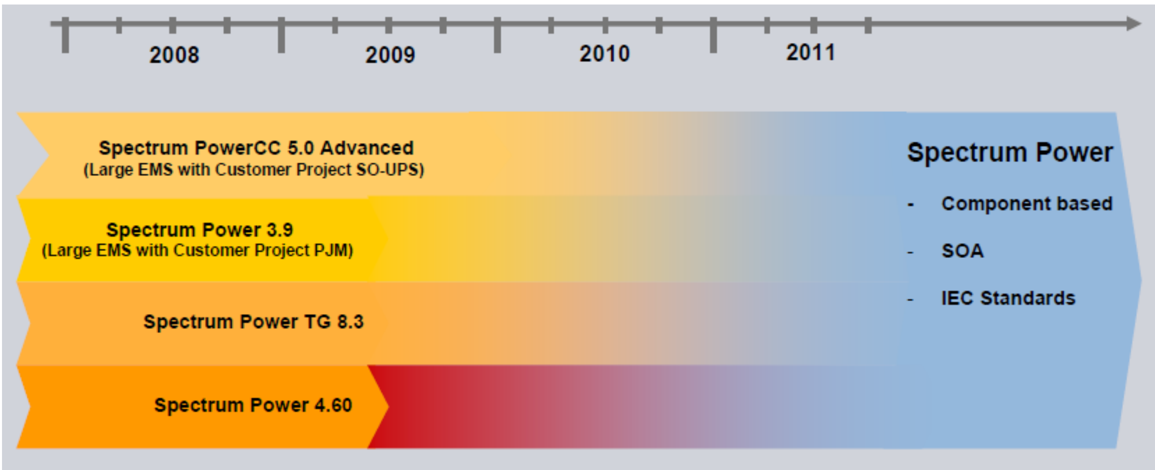


Figure 5-34 : Siemens SCADA Control Centre Applications Product Portfolio Evolution

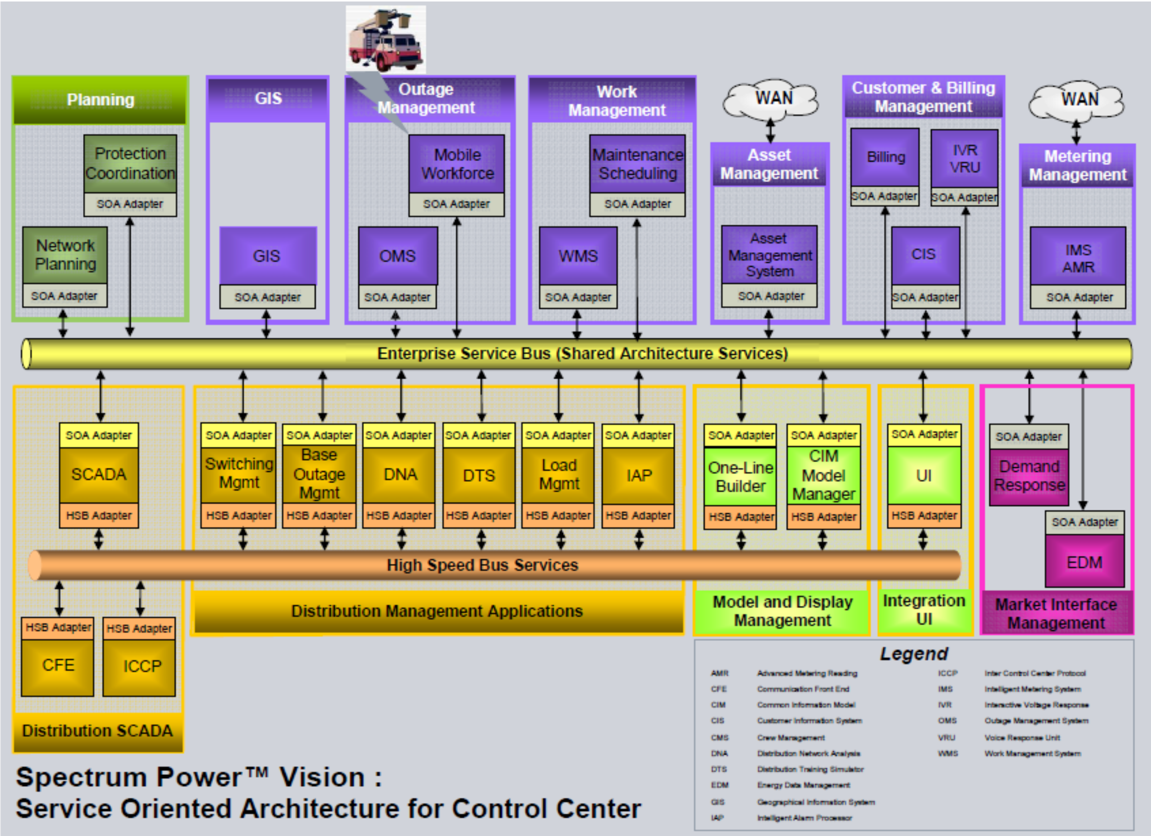


Figure 5-35 : Siemens Spectrum Power Control Centre Applications - Architecture Vision

5.24.2.3 Real-Time Interface to Other Control Centres

Vector is planning to implement real-time data exchange with the Transpower SCADA system, via Vector's Siemens Spectrum Power TG Inter-control Centre Communications Protocol solution (ICCP per IEC60870-6 TASE.2 Standard).

Inter-utility real-time data exchange of real-time and historical power system information, including status and control data, measured values, scheduling data, energy accounting data and operator messages is becoming increasingly important and is a vital link in ensuring the maximum benefit from future smart grid operations. The open standard based secure communication links among the utility control centres are identified in Figure 5-37 (IEC 60870-6 TASE.2 Inter-control centre communications (ICCP)).

At present, Vector has very limited SCADA information of the Southern network sub-transmission lines connected to Transpower substations eg. no status indication and control capability of Vector's supply lines circuit breakers, circuit loading information, etc. From a network operational excellence perspective this is a significant deficiency.

The Northern region SCADA information of the sub-transmission lines connected to Transpower substations is provided via Vector's "legacy" protocol interface to the Transpower RTU at each site. As a planned part of Transpower's substation automation modernisation programme the support of the "legacy" protocol (Vector LN2068 SCADA master station Conitel 2020 / 2025) interface will no longer be supported and, if not addressed, would provide a similar deficiency in information about the Northern region interconnections as is experienced in the Southern region.

In addition to these above operational issues, Vector needs to protect its network against potential situations of excessive circulating current condition resulting in outages, should temporarily paralleling of Transpower GXPs occur inside the Vector network. This can be avoided if real-time voltage magnitude and phase angle of Transpower supply busbars is available for load flow calculation, for which a SCADA interface with Transpower is required.

IEC 60870-6 TASE.2 (ICCP) is a global standard that is very widely used by many utilities for inter-control centre communications between SCADA and/or EMS (energy management system) systems (USA, Europe, Australia etc). It is supported by most vendors of SCADA and EMS systems. Transpower has evaluated a number of options to exchange data with the third parties, and has concluded that ICCP is the only solution that:

- allows fast provisioning of new connections;
- can be efficiently and effectively secured;
- is standards-based and in widespread use;
- allows bi-directional exchange of data & controls;
- is simple architecture and scalability;
- provides good native resilience;
- is based on open standard and has multi-vendor support; and
- provides low cost integration options.

The intended flow of inter-control information between utilities is illustrated in Figure 5-36.

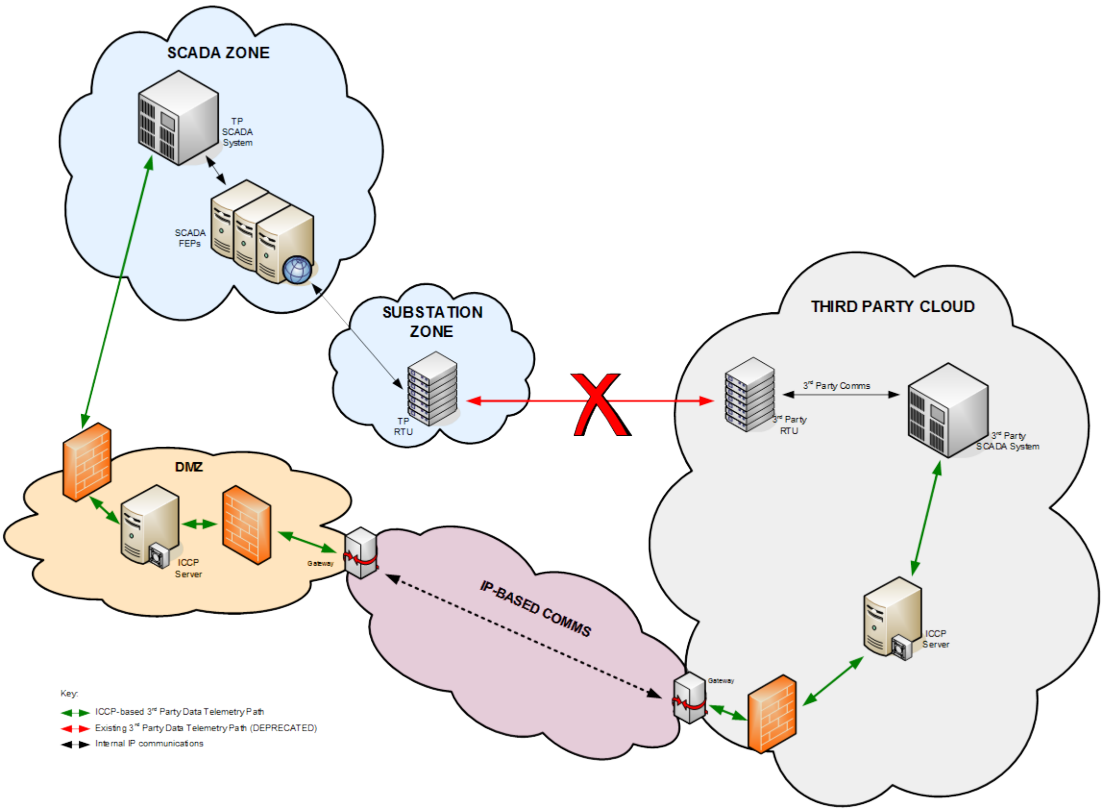


Figure 5-36 : Future Inter-control Centre Information exchange among NZ utilities

Vector completed a feasibility study to establish an ICCP link with Transpower in 2003.

Vector's Siemens Spectrum Power TG master station supports ICCP, as shown in Figure 5-36 (Control Centre Gateway). The Transpower SCADA master station is capable of secure ICCP information exchange with the third parties. ICCP is Transpower's preferred future proof option for data exchange with the third parties.

ICCP also provides a means of reaching beyond SCADA systems to other utility database systems such as historians (data collection and storage), outage and scheduling systems, to facilitate exchange of data for uses over and above than real-time power system control and supervision. This will provide possible business opportunities and challenges for sharing resources and competing for operating and power system management services.

The immediate benefits for Vector of an ICCP link to Transpower's SCADA master station include:

- Obtaining data originating from Transpower substations would no longer require any Vector equipment at the Transpower substations;
- Existing Vector SCADA communications circuits into Transpower substations would no longer be required;
- Vector's total communications requirements would be simplified;
- Lower lifetime costs for obtaining data from Transpower sites;
- Easier to make changes to data obtained from Transpower sites;
- ICCP is truly scalable with low incremental cost and expansion only limited by master station capacity and ICCP network bandwidth;
- Higher reliability communications by utilising Transpower's existing redundant network to site;
- Greater data integrity through lower risk of any Transpower site works inadvertently affecting Vector data transfers; and
- Complete flexibility for configuring controls and data acquisition.

5.24.2.4 Penrose to Hobson Tunnel Management System

The tunnel management system is used to monitor:

- Tunnel ventilation;
- Drainage sump level control;
- Status monitoring (temperature, levels);
- Alarm monitoring (fire);
- Visualisation & control (HMI functions); and
- Access control via airlocks.

The system consists of range programmable logical controllers (PLC) made by Siemens S7-200 and S7300 connected in an optical fibre ring. The PLCs are interfaced to a Citect SCADA application, which runs on a stand-alone a desktop computer, via Ethernet / IP network.

This Citec SCADA hardware and application are no longer supported and represents a risk in case of failure. It is, therefore, intended to directly interface field PLC devices to Siemens Spectrum Power TG application and then decommission Citec SCADA application.

5.24.3 Network Automation at Vector

Power system automation schemes are being implemented at Vector to support reduced customer outages, increased network utilisation, cost efficiency and increased system reliability.

Vector's current substation automation system is based on IEC 61850 - *Communication networks and systems for power utility automation standards*. The substation LAN is based on a resilient optical ethernet and the connected IEDs are IEC 61850 standard compliant. Over 50% of Vector's primary substations are equipped with IEC 61850 compliant IEDs.

5.24.3.1 Control Centre Automation - Load shifting scheme based on CIM / IEC 61850 model

An automation scheme is being developed to transfer network load between adjacent substations under overloading or fault conditions. This is intended to increase asset utilisation and provide an opportunity for substantial cost efficiencies. The scheme, illustrated in Figure 5-37, is based on the information and communication standards adopted by Vector.

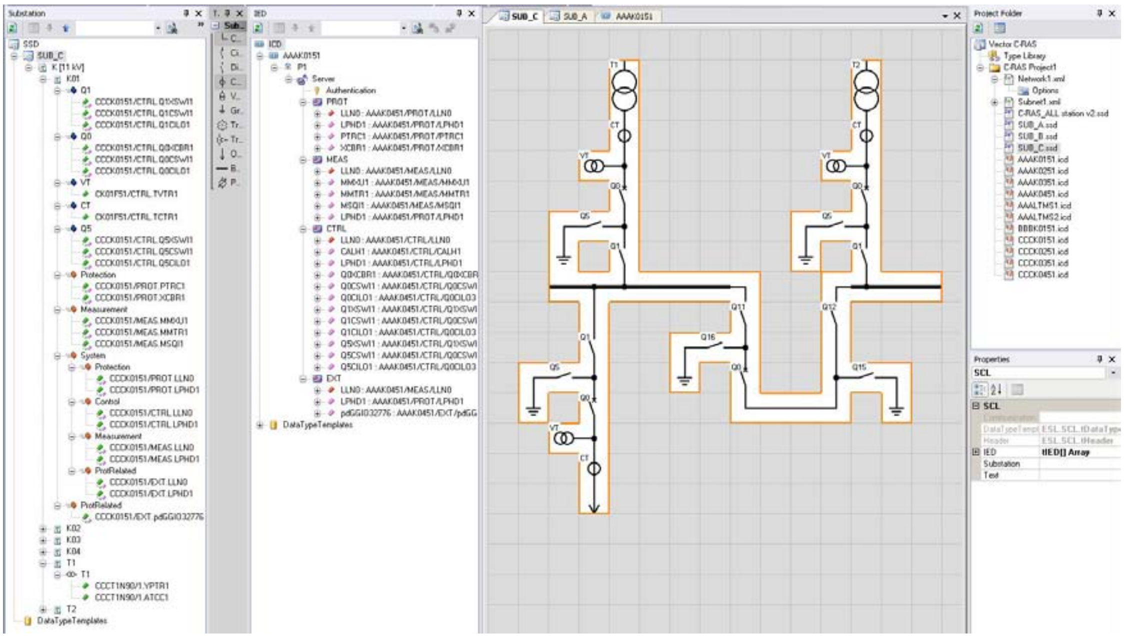


Figure 5-37 : Network automation scheme

5.24.3.2 Substation Automation

Substations constitute the electric power system nodes for all access and information retrieval. Substation automation describes the collection of infrastructure within a substation enabling the co-ordination of protection, automation, monitoring, metering and control functions, and utilising substation internal communications network infrastructure. Vector's substation automation system is based on resilient optical ethernet local area networks, running IEC 61850 compliant IEDs.

Substation automation is not just the automation of a substation. It is part of a major paradigm shift for all power system operations. It is the first step toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions and supports the planning and asset management necessary for cost-effective operations.

A typical substation automation system, as applied on the Vector network, is illustrated in Figure 5-38.

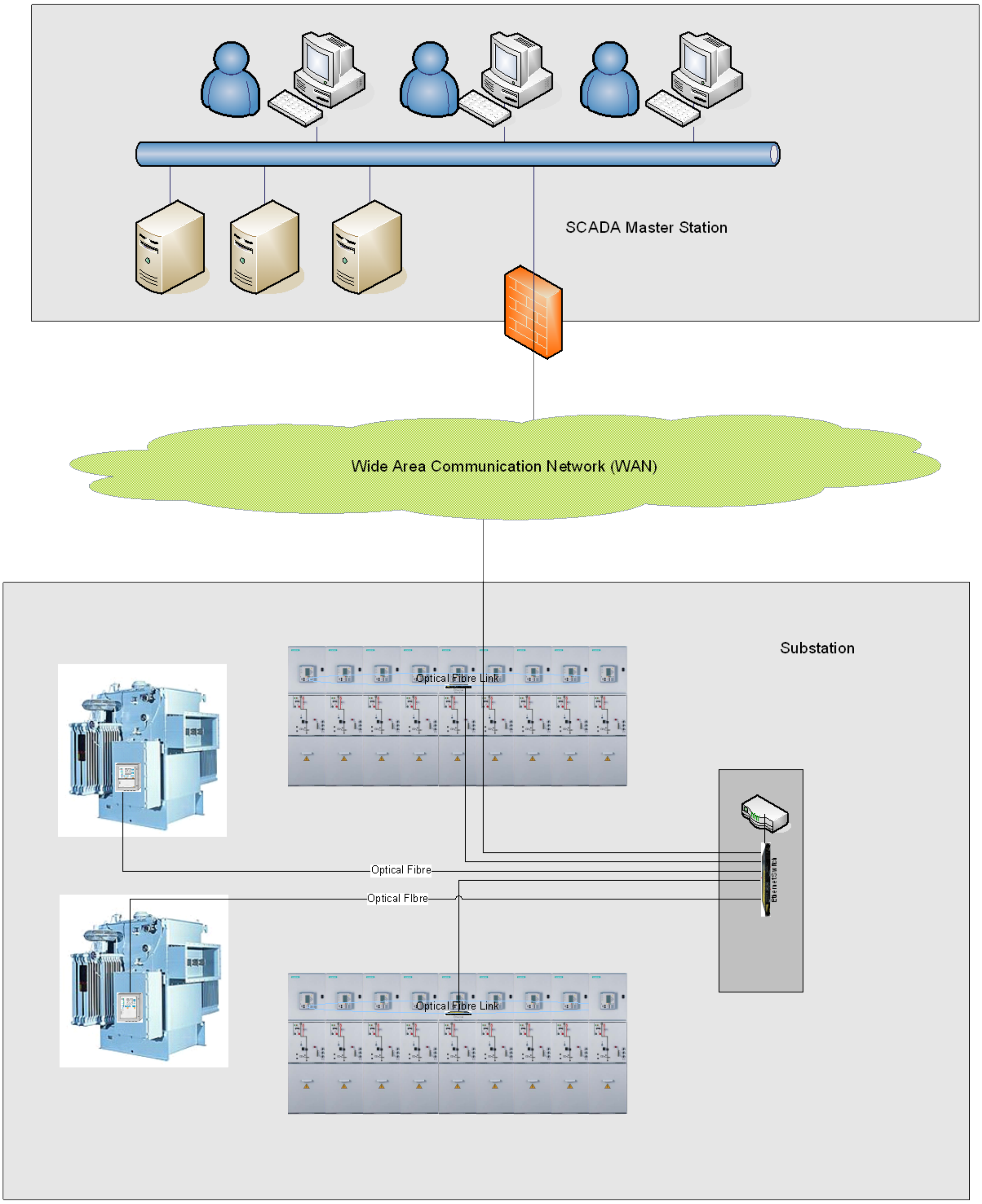


Figure 5-38 : Vector's typical substation automation system

The following automation schemes are being implemented:

- Centralised substation bus load-transfer schemes;
- Centralised substation overloading load shedding scheme; and
- Centralised substation under-frequency load shedding scheme.

The automation schemes are based on the IEC 61850 standard and peer-to-peer relay communication over the substation LAN. The algorithms for the schemes are centralised in the incoming IEDs. These schemes, illustrated in Figure 5-39, increase reliability, as all incoming IEDs have the same algorithm and execute the programme automation sequence and issue the control command concurrently.

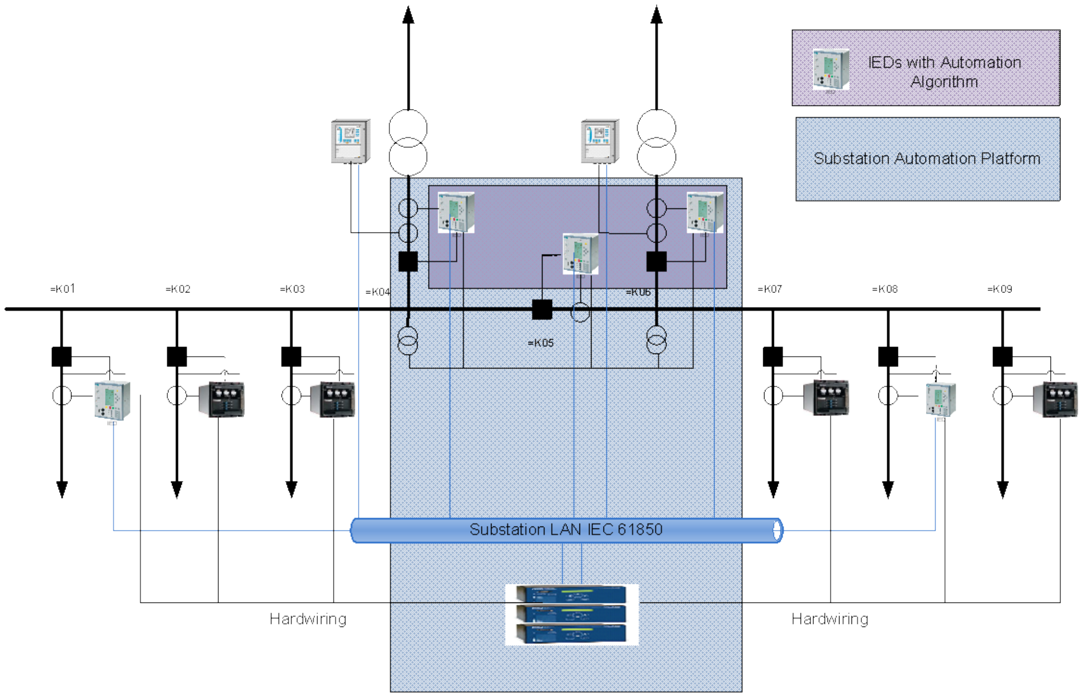


Figure 5-39 : Substation automation scheme

a. Centralised substation bus load-transfer schemes

At the substations, a situation arises from time to time where fault current level can exceed the switchgear fault current ratings. This presents safety risks to people and equipment.

To reduce fault levels, and avoid switchgear replacement, the network has been split at substation busbars by opening bus-section circuit breakers. This, however, impacts on network reliability, as under incomer fault conditions switching is required to restore supply from the other side of the switchgear bus.

This situation is alleviated by a substation centralised automatic busbar load transfer scheme. The scheme is designed to automatically close the bus section circuit breaker upon loss of one of the incoming feeders.

b. Substation Centralised Overload Load Shedding Scheme

Owing to increased substation loading, a loss of a substation incoming feeder can result in overloading of the primary equipment (eg. power cables, power transformers) associated with the remaining incoming feeder(s). The equipment overloading can lead to accelerated asset ageing, equipment failure or loss of supply to large numbers of customers due to overload tripping.

A substation centralised automatic feeder load-shedding scheme has been designed and implemented in order to mitigate these consequences. The basic operation of the load-shedding scheme is to detect when one of the incomers has tripped, to continuously check loading conditions on the remaining incoming feeders and to shed as many outgoing feeder loads as required to prevent tripping of the remaining incomers.

This may result in a loss of some customer load, but the extent of outages will be far less than that which would result from further incomer trips while also protecting the assets.

c. Substation Centralised Automatic Under-frequency Load Shedding Scheme

The frequency of a power system changes when the load-generation equilibrium is disturbed. If the unbalance is caused by a deficiency in generation capacity, the system frequency decays to a level value at which load-generation equilibrium is re-established. If equilibrium, however, cannot be established system collapse will occur, leading to widespread and possibly prolonged outages.

Vector is required to provide an Automatic Under frequency Load Shedding (AUFLS) scheme under the EGRs. The EGRs require electricity distribution utlilities to provide 2x16% (of the total load at the time) blocks of customer demand which can be shed automatically via the AUFLS when the grid frequency drops to 47.8Hz and 47.5Hz respectively.

A substation centralised AUFLS scheme is realised through using the incoming feeder IEDs. When under-frequency conditions arise the IEDs initiate load shedding based on the predefined outgoing feeder priorities, by tripping feeders via the substation RTUs via peer-to-peer communication (using the IEC 61850 standard).

5.24.3.3 Distribution Feeder Automation

Feeder automation can be defined as schemes of equipment (automated switches, auto-reclosers etc) capable of acting without human intervention in order to minimise outages, restore supply or carry out other network/asset automation functions eg. substation off-loading. The feeder automation schemes are frequently interfaced to the network control centre for remote indication, control and data acquisition (SCADA functions).

Vector's existing feeder automation schemes enables SCADA functionalities, auto-reclosing, auto-sectionalising, feeder reconfiguration, fault detection and voltage control. Over 300, mostly overhead line pole mounted, switchgear (load-break switches, auto-reclosers and sectionalisers, RMU) have been deployed. GPRS/3G IP (Internet Protocol) centric third party communication network and DNP3 communication protocol have been used for SCADA master station and engineering applications. The standard Vector deployment is shown in Figure 5-40.

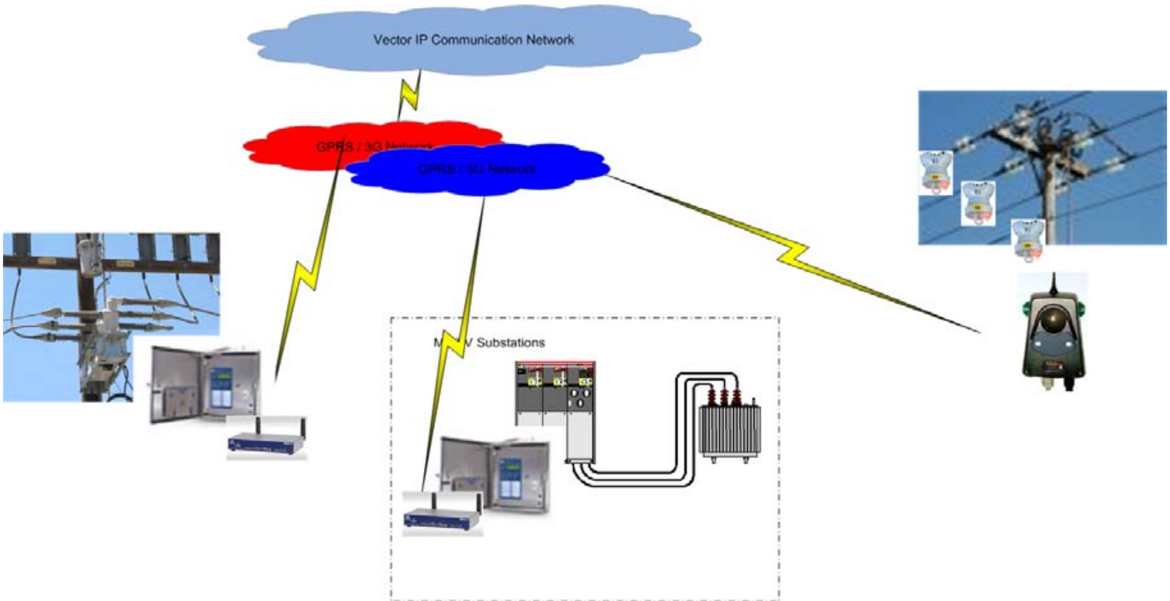


Figure 5-40 : Automation - Using GPRS/3G Communication System

5.24.3.3.1 MV/LV substation - Metering and Monitoring

In order to improve fault location, optimise asset management for the 11kV and LV networks, as well as to improve visibility of the LV network and power quality over the whole of the Vector distribution network, situation it is planned to roll-out MV/LV metering and monitoring equipment at selected sites over a 10 year period. (See also the discussion in Section 3.)

Vector has piloted a solution that includes optical current sensors that are interfaced to the control center via IEC 61850 and 3G communication networks. This is illustrated in Figure 5-41.

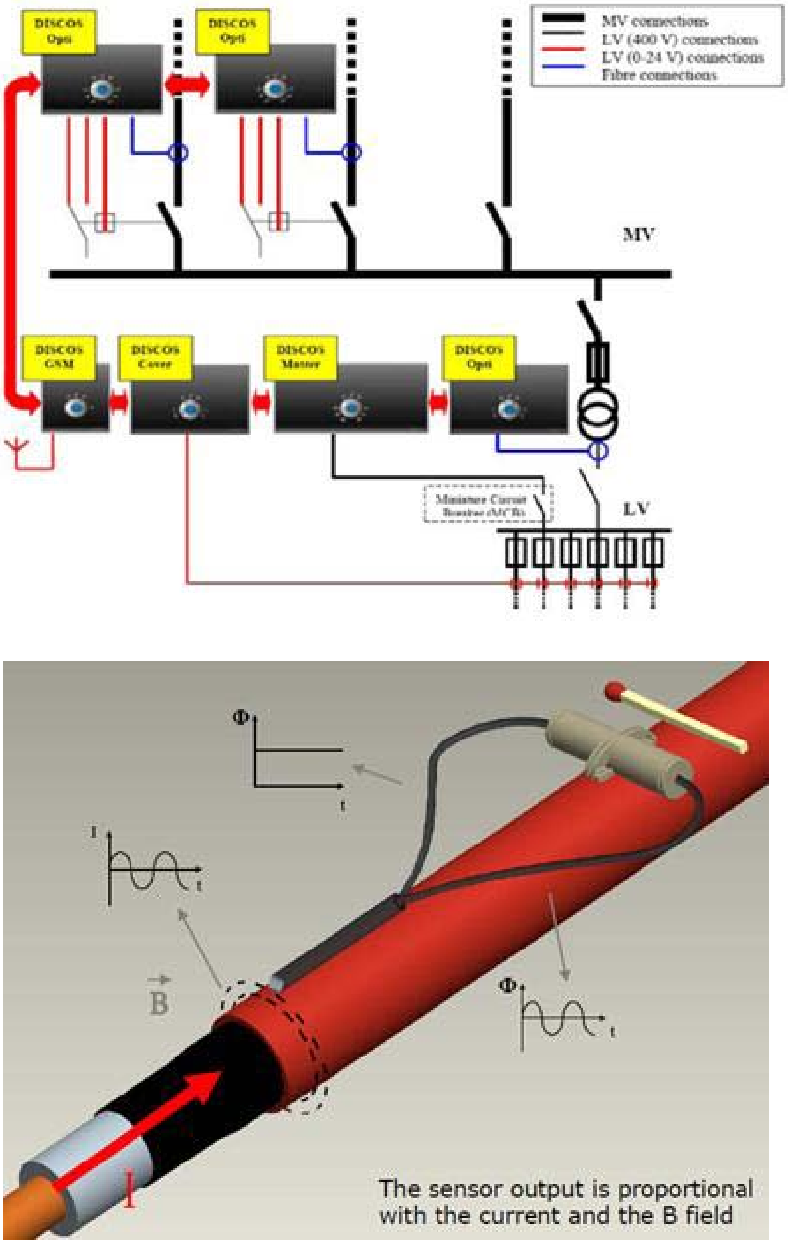


Figure 5-41 : Typical monitoring solution for a single transformer MV/LV distribution substation

5.24.3.4 Remote Terminal Units (RTU) Replacement

The RTUs used on the Vector network are microprocessor controlled electronic devices, which interface objects in the physical world (eg. switchgear, power transformers etc) to a distributed control system or SCADA system by transmitting telemetry data to the system and/or altering the state of connected objects based on control messages received from the system:

- Over time, a number of different RTUs have been installed in Vector's network many of which are nearing the end of their technical life or are obsolete.
- In the Southern region there are 40 Plessey GPT RTUs and Siemens PCC systems to be replaced in the coming years.
- In the Northern region 33 Foxboro C225 RTUs and 3 Foxboro C50 RTUs are planned for replacement.

Vector has standardised on the open industry standards (the IEC defined www.iec.ch) for the distribution and substation automation technologies, the operational communication network (ethernet/TCP/IP) and communication protocols (IEC 61850) from the field to the SCADA master station applications.

RTUs installed in the Northern region are interfaced to both of Vector's SCADA master station systems (Siemens Spectrum Power TG and Foxborough) as the Siemens Spectrum master station provides redundancy for LN2068 DNP3 / Conitel 2020/2025 protocol converter.

Vector has been running an annual RTU replacement programme for a number of years, and is currently replacing approximately 10 RTUs per region per annum. To replace conventional RTUs, two approved solutions have been used, traditional SCD5200 RTUs with a migration path to IEC 61850, and fully compliant IEC 61850 solutions from SEL.

5.24.4 Technical Application Integration

Increased use of "intelligent" devices utilises ever-increasing volumes of automation and technical analysis applications to optimise planning, design, operations and maintenance activities. Robust and highly integrated communications and distributed computing infrastructures are required for this. This infrastructure needs to be interoperable and easily integrated across vendor equipment and across the utility business. To achieve the necessary level of interoperability and low cost integration of the complex application requires adoption of a suite of the industry standards.

The reference architecture (Figure 5-42) identified the key standards, IEC 61850 and IEC 61968/IEC61970 (CIM - Common Information Model, GID – Generic Interface Definition) that facilitate interoperability and standardised information exchange.

IEC 61970/61968 standardises:

- A shared device information (data) model:
  - CIM / XML; and
- A shared set of services:
  - The Generic Interface Definition (GID).

CIM is an abstract data model that is used to represent the major objects in an electric utility enterprise and facilitate the application integration. Figure 5-42 shows the integration architecture as defined in the IEC 61968-1 standard.

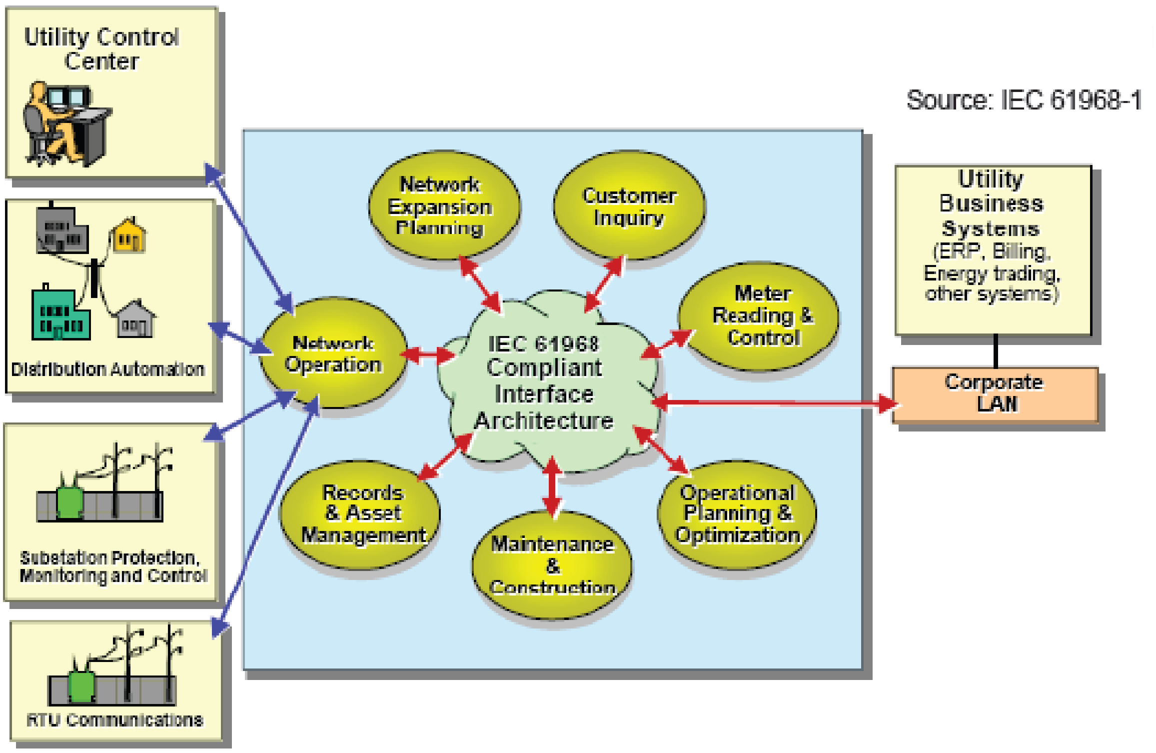


Figure 5-42 : Distribution management system with IEC 61968 compliant architecture

IEC 61968/IEC61970 (CIM/GID) standard-based solutions are to be used for Vector technical application integrations. The advantages of using CIM/GID based application integration are:

- Vector already has a large population of field installed devices supporting IEC 61850 standard and harmonisation of the IEC 61850 and the CIM model is under way;
- IEC 62351 standard is to address cyber security issues for CIM;
- Many of Vector's applications are being developed to be CIM Compliant (DIgSILENT Power Factory, Power Factory Station Ware, Siemens Power TG Master Station etc); and
- Lower integration cost.

The diagram in Figure 5-43 shows the proposed application and integration of the Vector control systems.

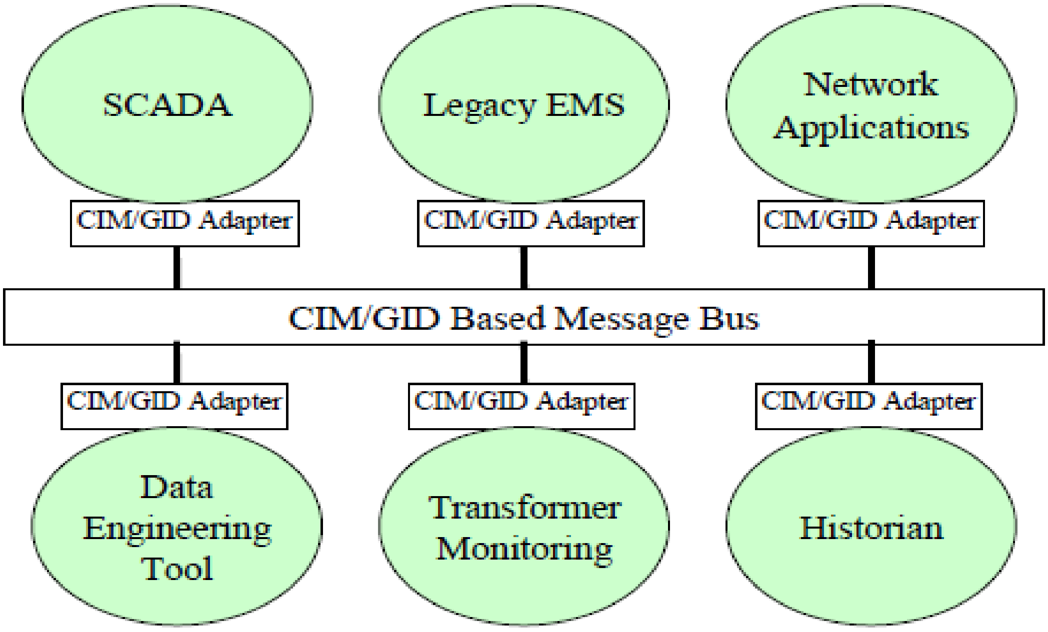
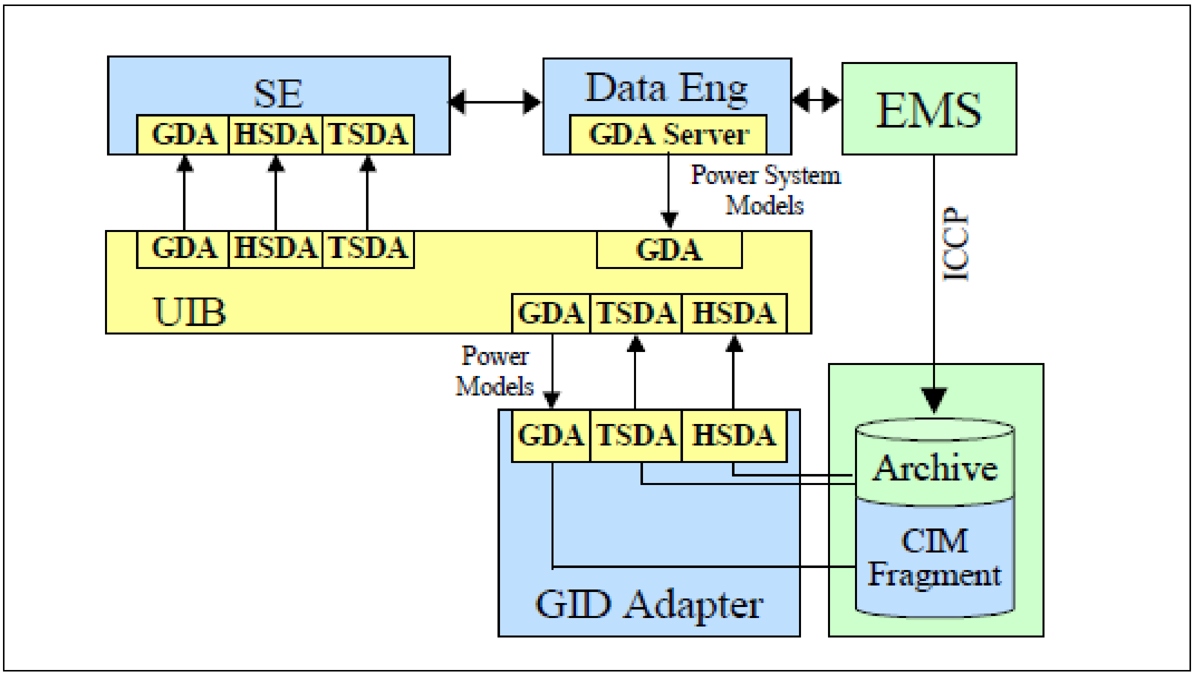


Figure 5-43 : Application integration scenario

5.24.4.1 Utility Integration Bus Topology (UIB)

The Utility Integration Bus (UIB) is a standards-based integration platform designed to significantly reduce the engineering effort required to integrate data in the utility environment. An approach to facilitate incremental upgrading of the Vector's control centre application integration is to use integration solution as shown in Figure 5-44.



API Name	Acronym	Description
Generic Data Access	**GDA**	Based on the Object Management Group (OMG) Data Access Facility (DAF) specification, GDA is used to access and modify model data in a model server and supports model change notifications.
Generic Eventing and Subscriptions	**GES**	Based on the OPC Alarm and Events (AE) specification, GES is used to publish and subscribe to XML messages using data in the context of a unified model.
High Speed Data Access	**HSDA**	Based on the OMG Data Access for Industrial Systems (DAIS) and the OLE for Process Control (OPC) Data Access (DA) specifications, HSDA is used for the exchange of real-time data in the context of a unified model.
Time Series Data Access	**TSDA**	Based on the OPC Historical Data Access (HDA) specification, TSDA is used to access time-based data from a historian in the context of a unified model.

Figure 5-44 : Specific GID interfaces used for application integration

A feasibility study to use the above approach is currently underway.

5.24.5 Communication Systems

Deployment of Vector's modern operational wide area communication network (WAN) infrastructure, on the open standard based IP, began in 2002. The WAN consists of the optical fibre infrastructure, digital communication over Vector's copper pilot cables, Vector's owned digital microwave radio links and third party IP network including wireless GPRS/3G GSM standard based networks. The IP network facilitates cost effective migration and integration of the operational services from obsolete disparate proprietary solutions to the open standard based solution. Over 50% of Vector substations have been connected via IP network. Hundreds of field installed apparatuses (auto-reclosers, load breaker switches, ring main units) are connected via third party GPRS/3G wireless communication networks.

Vector's standard substation LAN and operational WAN is based on Ethernet and IP communication technology. The ethernet/IP based operational communication network carries a number of services:

- SCADA (telecontrol and telemetering);
- The telemetry service(s) have QoS assigned, so that performance is not unduly compromised by other traffic sharing the same network;
- Engineering access (remote equipment management, on-line equipment monitoring);
- Digital fault record retrieval;
- Substation telephony – (voice over IP);
- Substation security;
- Video imaging and streaming video over IP is a future application impacting security and health and safety;
- Network management;
- Management of the network devices, routers, switches, and in the future SNMP management of the IEDs is an essential service; and

- The substation telephone is an essential tool for technicians and engineers working on site.

Choosing the right communications technology is key to creating an intelligent platform that can continually monitor utility assets, operations and consumer demand. The deployment of ethernet and IP based communication systems has become pervasive for a wide range of applications. There has been a rapid development of “networking standards” frequently involving active industry user and supplier organisations.

With current technology it is possible to develop a large, peer, autonomous and scalable network. TCP/IP facilitates a logical, low cost and easy solution to manage systems based on heterogeneous technologies by providing a common communication protocol for disparate communication technologies eg. Vector uses copper (Cu) pilot cables, digital microwave radios, optical fibres, Vodafone GPRS/3G to carry its SCADA communication using TCP/IP protocol. A future network in which all the elements (smart meters, home appliances, home energy management platform, infrastructure devices, plug-in vehicles etc) support IP will allow utilities and consumers to enjoy the benefits of a competitive and innovative ecosystem built around open standards.

Teleprotection over IP, remote asset management, video surveillance are being planned.

Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and IP based communication technologies. TCP/IP facilitates a logical, low cost and easy solution to incorporate and manage heterogeneous technologies by providing a common communication protocol eg. Vector uses copper (Cu) pilot cables, digital microwave radios, optical fibres, Vodafone GPRS/3G to carry its SCADA communication using TCP/IP protocol. Vector’s standard substation LAN and operational WAN are based on ethernet and IP communication technology, as illustrated in Figure 5-45 and Figure 5-46.

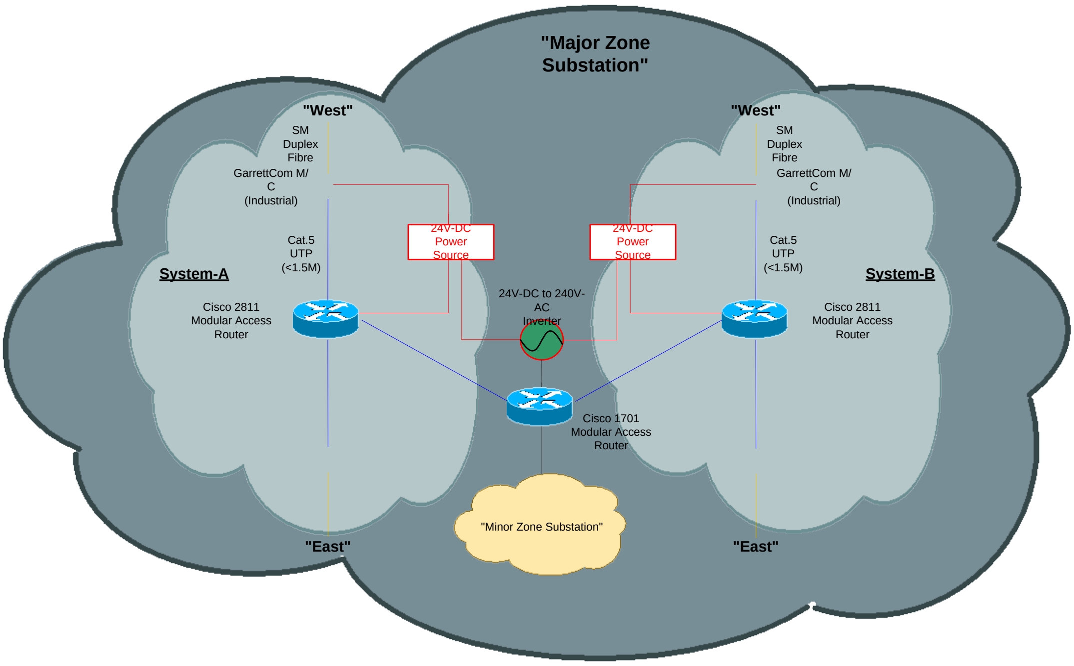


Figure 5-45 : Vector's IP WAN

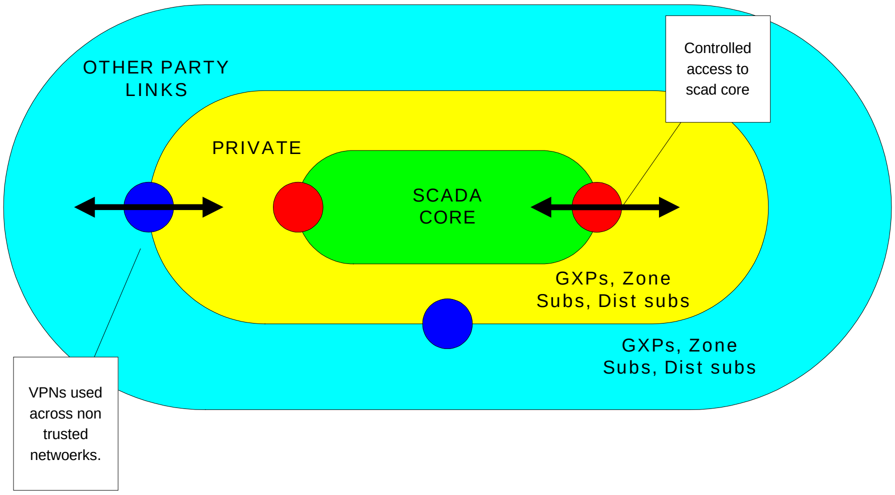


Figure 5-46 : Operation IP Communication Network - Private and Public Zones Boundary

Migration to an IP based network started in 2002. Vector will continue to introduce IP to its substations in conjunction with the network development or protection and control upgrade projects. Within the next five years it is planned that all zone substations will be connected via IP network. The substation communication network is provided by Vector Communication and other third parties, including Telecom, Vodafone and Transpower.

5.24.6 Cyber Security

The public electric power system is now characterized as one of several critical infrastructures, requiring rigorous application of security practices. Cyber security must address not only deliberate attacks, such as from disgruntled employees, industrial espionage, and terrorists, but also inadvertent compromises of the information infrastructure due to user errors, equipment failures, and natural disasters.

For Vector's real-time information and communications systems the cyber security strategy is focused on prevention, while also defining a response and recovery strategy in the event of a cyber attack. Cyber security risk assessment of Vector's real-time systems is applied to both Vector's power and information infrastructure.

The diagram in Figure 5-47 shows the security requirements, threats, counter-measures, and management at Vector.

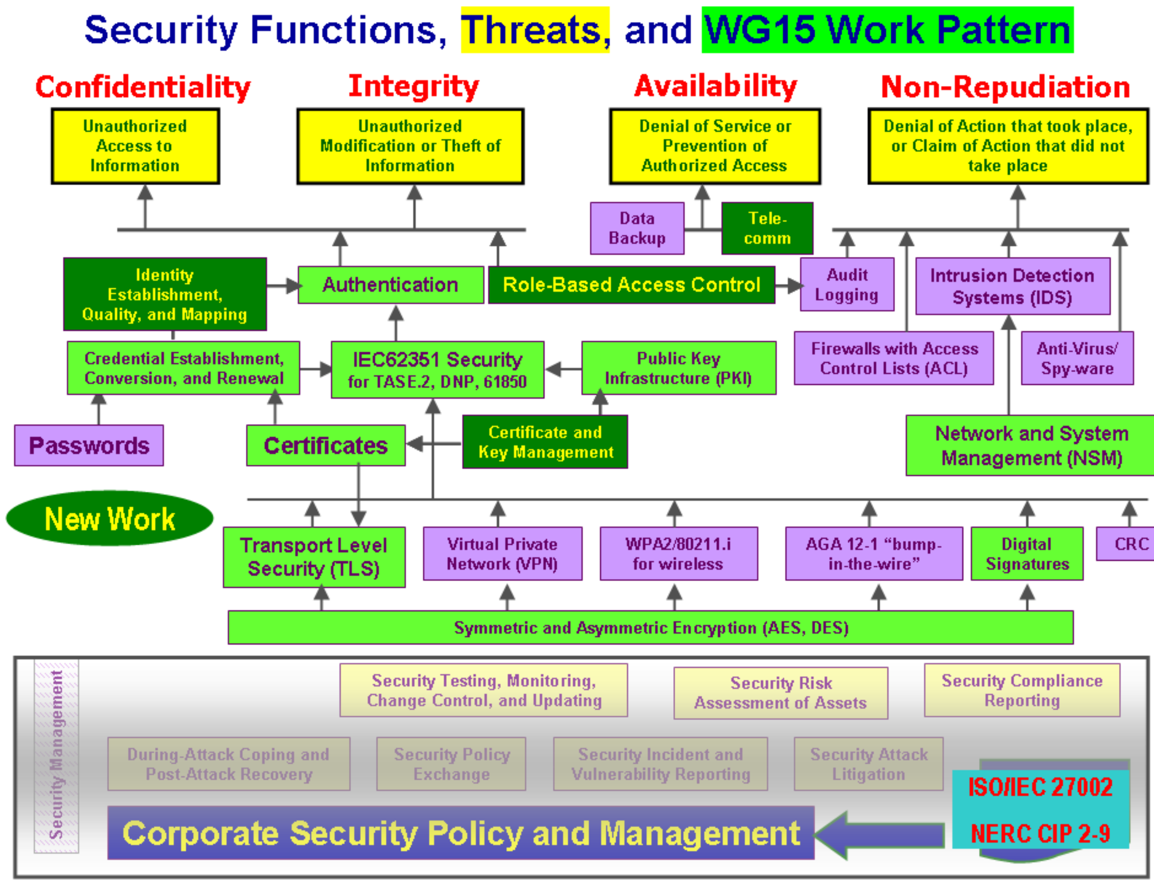


Figure 5-47 : Overall Security: Security requirements, threats, counter-measures, and management

Communication protocols are one of the most critical parts of power system operations, responsible for retrieving information from field equipment and, vice versa, for sending control commands. Vector is committed to IEC specified communication protocol for its real-time system and application interfaces (Figure 5-48). IEC TC57 has published a set of standards for information security for power system control operations (IEC 62351) to security IEC 60870-5, its derivative DNP, IEC 60870-6 (ICCP), IEC 61850, IEC 61968 and IEC 61970 communication protocols, as illustrated in Figure 5-48.

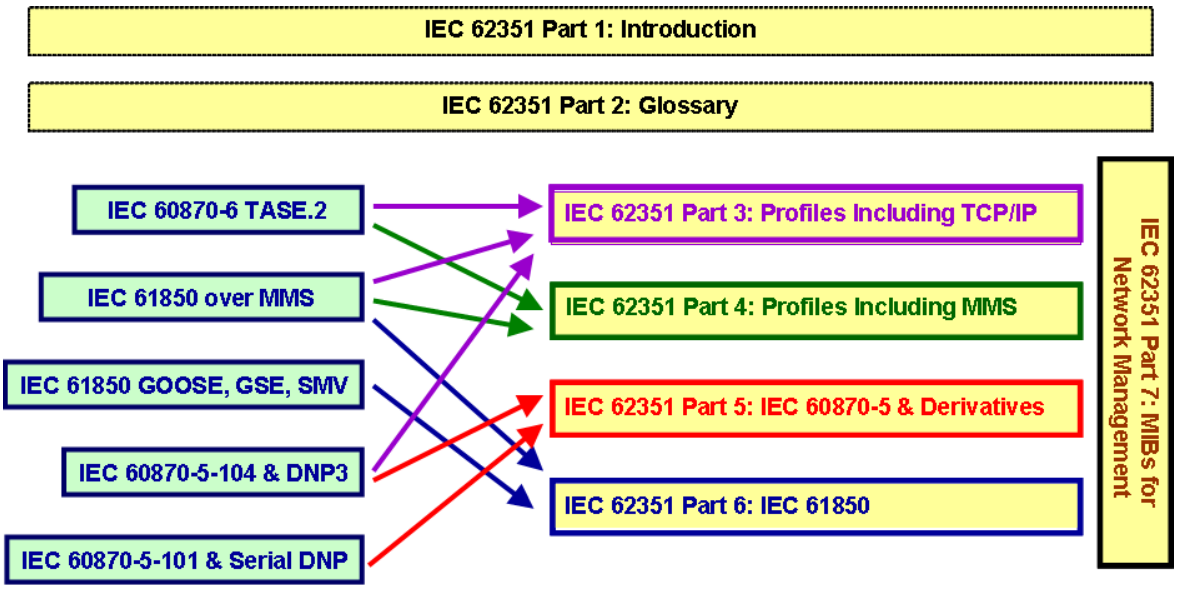


Figure 5-48 : Mapping of TC57 communication standards to IEC 62351 security standards

Vector is in the process of incorporating IEC 62351 standard protocol security enhancements within the communication protocols it uses for its protection, automation and control systems. New products, when they become available in the products and are practicable to be implemented, will adhere to this standard.

Following a detailed audit in 2009 into the cyber-security standards of Vector's SCADA network, several recommendations for improvement were made. In response, Vector's real-time systems information security policy and management have been enhanced within Vector's overall IT security policy and management. This has been developed in accordance to ISO/IEC 27002 standard and extended to incorporate real-time system specific requirements as defined by NERC CIP standards.

Other programmes are also underway to ensure the roles and responsibilities for the SCADA system, which lie across the business, are clearly allocated, and that adequate firewall protection and intrusion detection is provided for all parts of the system.

5.24.7 Substation Information Management

By using object-modelling technology, IEC61850 establishes a standardised self-describing object names structure for substation information. This is discussed below.

5.24.7.1 Digital Fault Recording Retrieval

Vector has implemented the automatic retrieval and archiving of power system digital fault recordings. The application enables timely analysis of substation and network events. It also contributes significantly to the reduction in time of post-fault investigations, problem identification and incident reporting. This is used to facilitate improved network and protection system performance.

5.24.7.2 Setting Management Modelling

Protection system modelling and settings is a vital part of network modelling and scenario simulations. Vector has implemented a protection setting management system (StationWare) from DIgSILENT that has an interface to the DIgSILENT network and protection tool, PowerFactory. Both products are planned to support IEC 61850 and CIM.

5.24.8 Time Synchronisation

Accurate and reliable time synchronisation is critical to ensure automatic control and system protection equipment operates correctly to allow optimal utilisation of network assets. When a system event occurs, it is important for later forensic analysis that all system events and data captured during the event are time stamped accurately so the root cause of the event can be determined. GPS time synchronisation plays a key role in Phasor Measurement Systems – a technique that permits the real-time visualisation of instantaneous power flows.

Time synchronisation of Vector's real-time systems is done using Network Standard Protocol (NTP). Fields installed IEDs are synchronised over an IP based wide area network to 1 ms resolution, using SNMP (Simple Network Time Protocol) according to IEC 61850 Standard.

Edition 2 of IEC 61850 Communication Network and Systems for Power Utility Automation Standards has adopted a precision sub-microseconds accuracy timing solution based on IEE1588v2 standard. In future, our new equipment will be compliant with this standard.

5.24.9 Energy and Power Quality Metering

Some businesses, such as those in manufacturing and service industries, have a high reliance on disturbance free power supply. One of the objectives of PQ monitoring is to identify disturbances that could adversely impact on customers' equipment with the objective of identifying solutions.

Vector's energy and PQ metering system consists of a number of intelligent web-enabled revenue class energy and PQ meters installed at GXPs and zone substations. The meters communicate to the metering central software over an ethernet-based, IP routed communication network. The meters are web enabled and the latest firmware version of the meters are compliant to the IEC 61850 standards (Vector's adopted information exchange standard).

The metering system provides Vector with essential information about the quantity, quality and reliability of the power delivered to Vector's customers and is currently used to:

- Improve asset utilisation by managing network peak demands;
- Provide PQ and load data for network management and planning purposes;
- Provide information to assist in the resolution of customer-related PQ issues; and
- Contribute to the power system stability by initiating instantaneous load shedding during under-frequency events.

The following strategies have been implemented to monitor and report PQ problems identified on Vector's network:

- PQ monitoring equipment has been installed at selected GXPs and zone substations;
- An electronic mail system automatically sends a PQ disturbance report in real-time to customers;
- A web-based reporting system that makes real-time and historical PQ information available for diagnosis of customer PQ issues;
- Use of network modelling software and tools to predict the impact of PQ disturbances at customer premises; and
- Using portable PQ instruments to investigate PQ related complaints.

The information in the PQ reports provide details on any event that caused voltage and current transients or voltage sags and swells in the network. By drilling down into each report the daily maximum/average/minimum of voltage, current, frequency, power factor, voltage unbalance, voltage total harmonic distortion (THD) and current THD can be observed. The voltage sags captured by each monitor for the same period can also be viewed as a voltage sag magnitude duration chart.

Other PQ action at Vector includes:

- Installation of PQ monitoring instruments at new zone substations. This is to increase the number zone substations being monitored and gain increased knowledge of the quality of supply to customers;
- Benchmarking the quality of supply on the network and monitor changes over time;
- Offering support to customers by assisting with solutions to PQ problems; and
- Developing an automated link between network events such as faults and data captured on the PQ instrumentation.

5.24.10 Development Plan

5.24.10.1 Current Projects

Domain	Project Description	Planned Completion Year	Value
Power System Protection	Replacement / Refurbishment based on asset condition / system adequacy with IEC 61850 compliant solutions	2011 - 2020	Operational Excellence
Network Automation	Control centralised automatic load shift scheme based on CIM / 61850 model – Proof of Concept	2011	Cost Efficiency
Network Automation	MV/LV secondary substation automation –based on IEC 61850 and IP network communication	2011-2020	Cost Efficiency
Network Automation	Centralised substation scheme • bus load-transfer schemes • overloading load shedding scheme • under-frequency load shedding scheme	2011-2020	Cost Efficiency
Network Automation	Substation Modernisation – RTU Replacement with IEC61850 based solution	2011 - 2015	Cost Efficiency Operational Excellence Future Proofing
Control Centre Applications	Completion of Migration of Northern SCADA LN2068 master station application to Siemens Power TG application - Implementation	2011	Cost Efficiency Operational Excellence Future Proofing

Domain	Project Description	Planned Completion Year	Value
Control Centre Applications	Upgrade of Siemens Sicam PAS applications to v7.0	2010-2011	Operational Excellence Future Proofing
Control Centre Applications	Power TG Master Station – Web Interface	2011	Cost Efficiency Operational Excellence
Control Centre Applications	Interface To Transpower SCADA System via Inter-control Centre Communications Protocol (ICCP) per IEC60870-6 TASE.2 Standard	2011-2012	Cost Efficiency Operational Excellence Future Proofing
Control Centre Applications	Interface Tunnel control and monitoring to Siemens Power TG Master Station Application	2011	Operational Excellence Future Proofing
Communication Networks and Systems	Continue Deployment of IP based substation LAN / WAN solutions	Ongoing	Cost Efficiency Operational Excellence Future Proofing
Information Management	DIgSILENT StationWare – Upgrade to new version	2011	Operational Excellence

5.24.10.2 Planned Projects

Domain	Project Description	Planned Completion Year	Values
Power System Protection	Replacement / Refurbishment based on asset condition / system adequacy with IEC 61850 compliant solutions	2010 - 2020	Operational Excellence
Network Automation	Substation Modernisation – RTU Replacement with IEC61850 based solution	2011 - 2020	Cost Efficiency Operational Excellence Future Proofing
Network Automation	Centralised substation scheme • bus load-transfer schemes • overloading load shedding scheme • under-frequency load shedding scheme	2011-2020	Cost Efficiency
Network Automation	Feeder Automation - Migration from proprietary network automation solution to Vector's standard based solution as part of the planned program distribution asset replacement	2011-2015	Cost Efficiency Operational Excellence Future Proofing

Domain	Project Description	Planned Completion Year	Values
Network Automation	Control Centre centralised automatic load shift scheme based on CIM / 61850 model – Pilot Project	2011	Cost Efficiency, Future Proofing
Network Automation	MV/LV substation automation – rollout IEC 61850 and IP network communication	2011 - 2020	Cost Efficiency Operational Excellence
Control Centre Applications	Power System Metering – Upgrade of ION Enterprise Application	2011	Operational Excellence Future Proofing Cyber Security
Control Centre Applications	Network Real-time Analytical Applications	2011-2015	Operational Excellence Future Proofing Cyber Security
Communication Networks and Systems	Continue Deployment of IP based substation LAN / WAN solutions	Ongoing	Cost Efficiency Operational Excellence Future Proofing
Communication Networks and Systems	Increase availability of third party cellular network for distribution automation.	2011 - 2011	Operational Excellence
Cyber Security	Project to address vulnerabilities	2011 - 2015	Operational Excellence

5.24.11 Protection & Control Development Expenditure Forecast

In Table 5-41 the network development expenditure forecast is broken down into broad expenditure categories. Note that customer initiated projects relate to those projects significant enough to initiate network reinforcement.

Financial Ending	Year	Mar 11	Mar 12	Mar 13	Mar 14	Mar 15	Mar 16	Mar 17	Mar 18	Mar 19	Mar 20
Protection, Automation Control, Communication		$6.30m	$6.30m	$6.70m	$6.30m	$9.10m	$6.30m	$6.30m	$6.30m	$6.30m	$6.30m

Table 5-41 : Expenditure on protection & control projects to 2020

5.25 Network Development Programme

Table 5-42 summarises the project programme for development of the power network in the two regions. The table below shows the current target completion dates for these projects, compared with that in the previous plan. If there is a difference the reasons for the change are described (advanced or delayed) in the following tables. Newly identified and completed projects are also highlighted.

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2011	Keeling Road	Reinforcement of Valley Road 11kV feeder	2011	Delayed
2011	Westgate	Zone substation land purchase	2011	Complete
2011	Wiri West	Zone substation land purchase	2011	Required for future substation
2011	Hobson	Supply to Victoria park roadway tunnel	N/A	Customer driven project
2011	Liverpool	Stage One of 11kV supply to Medical School	2012	Project underway, brought forward due to revised customer requirement
2011	Sylvia Park	Sylvia Park 11kV feeders to offload CARB 10 and 18	2016	Project underway, brought forward due to revised load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2011	Browns Bay	Stapleford 11kV feeder	N/A	New project to offload Torbay substation
2011	Newmarket South	Purchase of land for new zone substation	2011	No change
2012	Orewa	Orewa zone substation - Weranui 11kV feeder	2012	Delayed due to subdivision work
2012	Chevalier	Chevalier two 11kV new feeders	N/A	Description changed
2012	Chevalier	Install second 33/11kV transformer	N/A	Customer driven project
2012	Atkinson Rd	Upgrade of zone substation	2011	Almost complete
2012	Rosedale	Zone substation land purchase	2011	No progress
2012	Waimauku	Zone substation upgrade: install second transformer	2011	Scope change
2012	Clendon	Reinforce Wiri South 11kV network	2011	Deferred
2012	Flatbush	Purchase of land for new zone substation	2011	Deferred
2012	Customer B	Stage 1 upgrade of supply to customer B	2011	Customer driven project
2012	Mangere East	Upgrade Supply to Customer A	2011	Customer driven project
2012	Warkworth	New 11kV feeder to Warkworth South (use 33kV cable)	2012	Initial design underway
2012	Hillsborough	Hillsborough auto load shifting scheme	N/A	New project
2012	Mt Albert	Auto load shifting scheme	N/A	New project
2012	St Heliers	Load shedding & auto shifting scheme	N/A	New project
2012	Helensville	Kaukapakapa/South Head 11kV reinforcement	2013	Brought forward

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2012	New Lynn	Totara Avenue 11kV feeder reinforcement	2013	Load forecast revised
2012	Avondale	11kV reinforcement for Waterview tunnel south portal	2015	Brought forward due to revised customer requirement
2012	Avondale	Avondale zone substation - establish 33kV switchboard	2015	Brought forward due to revised customer requirement
2012	Maraetai	Reinforce 11kV feeder nine	2015	Project brought forward
2012	Waterview	Waterview - South portal sub for 16MW TBM	N/A	New project due to revised customer requirement
2012	Waterview	Waterview - 11kV reinforcement - Yard 2-3-5-10-11-12	N/A	New project due to revised customer requirement
2012	Hobsonville	New 11kV feeder to offload Oriel feeder	N/A	To offload Oriel feeder
2012	Penrose, Westfield	Ontrack: power supply cabling	N/A	New project requested by customer
2013	Penrose tunnel	Enhanced fire suppression for Transpower cables	2013	No change
2013	Otara	New 11kV feeder	2011	Deferred
2013	Rosedale	Establish a zone substation in Rosedale	2013	No change
2013	Rosebank	Rosebank North zone substation - land purchase	N/A	New project
2013	Highbury	Install second 33/11kV transformer	2016	Brought forward due to revised load forecast
2013	Te Atatu	Waterview tunnel SH 16 Te Atatu - nth portal ducts	N/A	New project due to revised customer requirement
2013	Swanson	Birdwood feeder extension	N/A	To offload the Bethells Rd feeder
2013	Mckinnon	Extend The Avenue feeder	N/A	To provide a backstop

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2013	Sylvia Park	Sylvia Park 11kV new feeders to offload Westfield feeders	2018	Brought forward due to revised load forecast, substation and description changed
2013	Rockfield	11kV feeders to off-load McNab feeders 16 and 29	N/A	Brought forward due to revised load forecast
2013	Quay	Retire ageing 110/22kV transformers and replace	2014	Brought forward
2013	Newmarket	Newmarket: new 11kV feeder to supply Farmers redevelopment	N/A	New project due to revised customer requirement
2013	Flatbush	11kV feeder reinforcement to Flatbush area	2013	No change
2014	Hillsborough	Install second 33kV cable and 33/11kV transformer	2016	Brought forward due to revised load forecast
2014	Greenmount	New 11kV feeder to Armoy Drive	2012	Deferred
2014	Hobsonville	Reinforcement of the Clark Road 11kV feeder	2014	Load growth slower than expected
2014	Hans	11kV feeder to reinforce Savill Drive	2013	Deferred
2014	Newton	Load shedding & auto shifting scheme	2013	Deferrred due to revised load forecast
2014	Takanini	11kV feeder to Porchester Road	2014	No change
2014	Hobsonville East	Zone substation land purchase	2014	No change
2014	Red Beach	Second 33/11kV transformer	2014	No change
2014	Balmoral	Reinforcement of 11kV network for St Lukes supply	N/A	New project
2014	Te Papapa	11kV reinforcement	2015	Brought forward due to revised load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2014	Westgate	Establish a new zone substation at Westgate	2015	Load forecast revised
2014	Belmont	New 11kV feeder	N/A	To reinforce Ngataringa Bay
2014	Highbury	New 11kV feeder	N/A	To offload Birkenhead feeder
2014	Hobson	Development of the airspace above Hobson substation in CBD	2013	Renamed
2014	Hobson	Installation of a 110kV switchboard as part of new GXP	2013	Deferred
2014	Quay	22kV switchboard extension	2013	Deferred
2014	Liverpool	Replace the number three 110/22kV transformer	2016	Brought forward
2014	Quay	Investigate 110kV GIS at Quay	N/A	New project
2015	Mangere West	Extend 11kV feeder two	2012	Deferred
2015	Remuera	Reinforce 11kV feeder no 12 from Remuera	2012	Deferrred due to revised load load forecast
2015	Otara	11kV feeder to Chapel Road	2014	Deferred
2015	Takanini South	Procurement of land for a zone substation	2014	Deferred
2015	Manurewa	Manurewa Super Clinic upgrade	2015	Customer driven project
2015	Orewa	Savoy 11kV feeder reinforcement (spare two extension)	2015	No change
2015	Sandspit	Establish zone substation	2015	No change
2015	Wainui	Zone substation land purchase	2016	Brought forward due to revised load forecast
2015	Warkworth South	Establish zone substation	2017	Brought forward due to revised load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2015	Waterview	11kV new feeders along Waterview tunnel for permanent supply	N/A	New project due to revised customer requirement
2015	Sandringham	Supply to south portal of Waterview roadway tunnel	2015	Customer driven project
2015	Atkinson Rd	New 11kV feeder	N/A	To offload the Kaurilands feeder
2015	Warkworth	New 11kV feeder	N/A	To offload Matakana feeder
2015	Te Atatu	Waterview tunnel supply, north portal	2015	Customer driven project
2015	Newton	11kV reinforcement to offload Newton feeders 9, 10 & 22	2018	Brought forward due to revised load forecast
2015	Liverpool	Medical School 11kV reinforcement stage two	2015	Customer driven project
2015	Hobson	Install a third 110/22kV transformer	2015	No change
2015	Customer B	Customer B upgrade Stage 2	2015	Customer driven project
2015	Quay	Designation and consenting process for the establishment of a 110kV substation plus detail design	N/A	Renamed
2016	Glenvar	Establish zone substation and reinforce 33kV network	2011	Deferred by 11kV reinforcement from Browns Bay
2016	Mangere East	Rearrange 11kV feeders 13, 15 and 19	2012	Deferred
2016	Rosebank North	Rosebank North zone substation - establish	2013	Deferred to coordinate with Waterview tunnel project
2016	Warkworth	Backstop for Whangateau 11kV feeder Warkworth zone SS	2014	Deferrred due to revised load load forecast
2016	Newmarket South	Establish a zone substation in Southern Newmarket	2014	Deferrred due to revised load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2016	Liverpool	Telecom Mayoral Drive 22kV feeders	2015	Deferred due to revised customer requirement
2016	Parnell	Parnell 11kV new feeder to offload NEWM 6 & 12	2015	Deferrred due to revised load forecast, substation and description changed
2016	Waiheke	11kV voltage regulator	2015	Deferred
2016	Helensville	Establish new Rodney GXP for future power plant	2016	No change
2016	Spur Rd	Wade River 11kV feeder reinforcement	2016	No change
2016	Kumeu	Zone substation land purchase	2018	Brought forward due to revised load forecast
2016	Hobson	Extend the 22kV switchboard	2013	Deferred
2016	Chevalier	Extend ex Waterview tunnel construction feeder to offload Mt Albert	N/A	Description changed
2016	Newmarket South	Investigation and concept design for Newmarket 110kV substation	N/A	New project
2016	Quay	Install a 110kV cable from Hobson 110kV switchboard to Quay, connect to second 60MVA transformer to create a 2nd "cable-Tx feeder"	N/A	Renamed
2016	Quay	Quay: construction of civil and building facilities for 110kV switchboard	N/A	Renamed
2017	Quay	Installation of 110kV switchboard	N/A	New project
2017	Waiwera	Zone substation land purchase	2013	Deferrred due to revised load load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2017	Quay	Ports of Auckland reinforcement	2013	Deferrred due to revised customer requirement
2017	Kaukapakapa	Establish zone substation	2016	Deferrred due to revised load load forecast
2017	Te Atatu	Upgrade 33/11kV transformers	2017	No change
2017	Brickworks	New 11kV feeder	N/A	To provide capacity for new subdivision
2018	Freemans Bay	22kV extension at Union St to offload FREE 13 & 15	N/A	deferred due to revised load forecast
2018	St Johns	33kV reinforcement	2013	Deferrred due to revised load load forecast
2018	Ellerslie	Establish zone substation	2015	Deferrred due to revised load forecast
2018	Flatbush	Establish a zone substation in Flatbush	2016	Deferred
2018	Coatesville	Install second 33/11kV transformer	2018	No change
2018	Oratia	11kV feeder to Piha from Oratia zone substation	2018	No change
2018	Takapuna	Install second transformer	N/A	To offload adjacent substations
2018	Newmarket South	Obtain consents and designation for the 110kV substation	N/A	New project
2019	Avondale	Avondale area 11kV reinforcement to offload AVON 1, 9 & 13	N/A	New project, load forecast reviewed
2019	Takanini	11kV Mill Road feeder from Takanini zone substation	2012	Deferred
2019	Waitakere	Establish zone substation	2012	Deferred by extended Birdwood feeder
2019	Hobsonville East	Establish zone substation	2015	Deferred by Clark Rd feeder

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2019	Waimauku	Install 33kV line	N/A	To provide a 33kV backstop
2019	Takapuna	New 11kV feeder	N/A	To offload Taharoto feeder
2019	Takapuna	New 11kV feeder	N/A	To offload Clifton Rd feeder
2019	Takapuna	New 11kV feeder	N/A	To offload Kitchener feeder
2019	Quay	Install a second 110kV cable from Hobson	N/A	New project
2019	Customer B	Customer B upgrade Stage 3		Customer driven project
2019	Newmarket South	Construction of civil and building facilities for new 110kV substation	N/A	New project
2020	Lincoln	Zone substation land purchase	2016	Deferrred due to revised load load forecast
2020	East Tamaki	Install NER at Greenmount	2016	Change of scope
2020	Mt Albert	Sub-transmission reinforcement	2019	Deferrred due to revised load forecast
2020	Hobson West	Designate site	N/A	New project
2020	Newmarket South	Long-term: cut and turn PEN-LIV 110kV cable to Newmarket south, install 110kV switchboard and two x 110/33kV transformers	N/A	New project
2021	Hillsborough	11kV new feeder	2013	Deferrred due to revised load load forecast
2021	Hobson & Quay	22kV feeders to Queens Wharf	2011	Deferrred due to revised customer requirement
2021	Newmarket	11kV supply to ex Lion Breweries site	2015	Deferrred due to revised load forecast
2021	Woodford	Second 33/11kV transformer + 33kV reinforcement	2018	Deferrred due to revised load load forecast

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2021	Keeling Road	Install second 33/11kV transformer and reinforce 33kV network	2020	Deferrred due to revised load load forecast
2021	Hobson West	Establish zone substation	2021	No change
2021	Quay	Install a third 110/22kV Transformer	2021	No change
2021	Victoria	Install 22kV switchboard	N/A	New project
2021	Quay	Extend 22kV switchboard stage 2	N/A	New project
After 2021	Rockfield	11kV feeder reinforcement	2013	Deferrred due to revised load load forecast
After 2021	Rosebank	11kV feeder reinforcement	2014	Deferrred due to revised load load forecast
After 2021	St Johns	11kV reinforcement to Auckland University Tamaki campus	2015	Deferrred due to revised load forecast
After 2021	Glen Innes	11kV reinforcement to off-load feeders six and thirteen	2018	Deferrred due to revised load forecast
After 2021	Kingsland	11kV reinforcement	2018	Deferrred due to revised load forecast
After 2021	White Swan	11kV reinforcement	2019	Deferrred due to revised load forecast
After 2021	Orakei	11kV reinforcement	2020	Deferrred due to revised load forecast
After 2021	Ellerslie	Install second 33kV cable and 33/11kV transformer	Deferred	Deferrred due to revised load forecast
After 2021	Glen Innes	upgrade Glen Innes sub-transmission & transformer to 33kV	Deferred	Deferred, pending assets condition assessment
After 2021	Onehunga	Upgrade Onehunga sub to 33kV	Deferred	Deferred, pending assets condition assessment
After 2021	Tamaki, proposed	Establish Tamaki substation	Deferred	Deferrred due to revised load forecast
After 2021	Westfield	Upgrade Westfield substation to 33kV	Deferred	Deferred, pending assets condition assessment

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
Cancelled	Warkworth	33kV line reinforcement	2011	Not required
Cancelled	Wiri	11kV Lambie Drive Feeder	2017	Cancelled
Cancelled	Wiri	Extend existing 11kV feeder	2011	Cancelled
Cancelled	Bairds	Reconfigure 11kV feeders one and two	2012	Cancelled
Cancelled	Otara	Otara zone substation - 11kV feeder nine reinforcement	2012	Cancelled
Cancelled	Manurewa	11kV feeder in Christmas Road	2013	Cancelled
Cancelled	Manurewa	11kV Feeder to Takanini	2013	Cancelled
Cancelled	Bairds	11kV reinforcement using ex 22kV cables	2015	Cancelled
Cancelled	Mangere Central	Establish Emergency Backstop to Customer B	2015	Cancelled
Cancelled	Manukau	11kV feeder to Cavendish Drive	2016	Cancelled
Cancelled	Manukau	11kV feeder to Te Irirangi Drive	2016	Cancelled
Cancelled	Greenmount	Reinforce 11kV to Crooks Road	2016	Cancelled
Cancelled	Greenmount	Reinforce 11kV to Lady Ruby Drive	2016	Cancelled
Cancelled	Mangere Central	11kV reinforcement	2017	Cancelled
Complete	Birkdale	Stanley Road 11kV feeder extension	2011	Completed
Complete	Bush Road	Schnapper Rock 11kV feeder reinforcement	2011	Completed
Complete	Te Atatu	Lincoln 11kV feeder (Woodford) reinforcement	2011	Completed
Complete	Waikaukau	33kV rearrangement	2011	Completed
Complete	Greenhithe	Establish zone substation and 33kV network extension	2011	Completed
Complete	Ranui	Establish zone substation	2011	Completed

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
Complete	Manurewa	Upgrade Supply to Customer C	2011	Complete
Complete	Liverpool	Liverpool substation - replace 110/22kV transformers	2011	Complete
Complete	Quay	Liverpool to Quay 110kV sub-transmission cables	2011	Complete
Complete	Wairau	Reroute 110kV OH circuits as part of enabling works for GXP	2012	Complete
Deferred	Northcote	Reinforce 33kV supply to Northcote zone substation	2020	Deferred beyond 2021
Deferred	Mangere Central	Installation of 11kV feeder to Massey Road	2013	Deferred due to changed customer requirements
Deferred	Greenmount	Install Auto Close device on 11kV bus	2016	Deferred beyond planning period
Deferred	Wiri West	Establish zone substation	2017	Deferred
Deferred	Takanini South	Establish zone substation	2018	Deferred
Deferred	Manly	Arkles Bay 11kV feeder reinforcement	2013	Deferrred due to revised load load forecast
Deferred	Orewa	Install a third 33kV circuit to Orewa zone substation	2015	Deferred beyond 2021
Deferred	Orewa	Centreway 11kV feeder reinforcement	2015	Deferred beyond 2021
Deferred	Manly	Reinforce 33kV cable Red Beach-Manly	2016	Deferred beyond 2021
Deferred	Orewa/Manly	33kV submarine cable upgrade	2016	Deferred beyond 2021
Deferred	Riverhead	33kV upgrade - circuit 22A (30m cable)	2016	Deferred beyond 2021
Deferred	Waiwera	Establish zone substation	2016	Deferred beyond 2021
Deferred	Wellsford	Te Hana 11kV feeder reinforcement	2017	Deferrred due to revised load load forecast
Deferred	Wainui	Establish zone substation	2018	Deferred beyond 2021

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
Deferred	Albany	Establish zone substation	2019	Deferred beyond 2021
Deferred	Kumeu	Establish zone substation	2019	Deferred beyond 2021
Deferred	Tomarata	Establish zone substation	2019	Deferred beyond 2021
Deferred	Milford	Reinforce 33kV supply	2020	Deferred beyond 2021
Deferred	Warkworth	Third 33kV overhead line	2020	Deferred beyond 2021
In ARP budget	Wairau	Replace outdoor 33kV switchgear with indoor switchgear	2012	Replacement project
N/A	Wellsford	Whangateau 11kV feeder reinforcement	2014	Duplicate
Not required	Ponsonby	Load shedding & auto shifting scheme	2012	Not required after cable rating reassessed
Not required	Drive	11kV load shedding scheme	2013	Not required after commissioning of Hillsborough new substation
Not required	Orakei	Load shedding scheme	2014	Not required after commissioning of St Johns new substation
Not required	Mt Wellington	Load shedding scheme	2020	Not required after commissioning of St Johns station
Not required	Avondale North	Establish zone substation	Deferred	Replaced with proposed Rosebank North substation
on going	Hobson	Extend 22kV feeders to Tank Farm development	2011	Description changed
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 11kV to 22kV load transfer	N/A	On-going
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 22kV switchboard extensions	N/A	On-going
	Southern	Future proofing ducts - Southern		

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
	Southern	Minor feeder reinforcements - customer initiated - Auckland		
	Southern	Substation load metering - Southern		

Table 5-42 : Project programme for network development

The expenditure and timing forecasts for the major projects included in Vector's development programme are listed in Table 5-43.

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Hobson	New GXP	$19.8m	$13.2m	$0.8m							
AIAL	33kV switchboard and third transformer	$6.8m									
Rosedale	New zone substation	$2.0m	$4.7m								
Waimauku	Second 33/11kV transformer	$1.8m									
Warkworth South	11kV reinforcement	$1.6m									
Hans	Additional capacity	$1.5m	$0.5m								
Waimauku	11kV reinforcement	$1.4m									
Wiri West	11kV reinforcement	$1.3m									
Highbury	Second 33/11kV transformer & 33kV reinforcement	$1.0m	$2.5m								
Avondale	11kV reinforcement	$1.0m									
Chevalier	11kV reinforcement	$1.0m									
Orewa	11kV reinforcement	$1.0m									
Avondale	33kV switchboard	$0.8m									
Rockfield	11kV reinforcement	$0.8m	$0.8m								
Liverpool	EMF mitigation	$0.8m									
Hobsonville	11kV reinforcement	$0.7m									
Sylvia Park	11kV reinforcement	$0.7m	$0.7m								
Waterview	11kV reinforcement	$0.6m									
Liverpool	Fire suppression	$0.6m	$0.1m								

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Te Atatu	33kV reinforcement	$0.5m	$0.5m								
Waterview	New substation	$0.5m									
Rosedale	Land purchase	$0.5m									
Penrose	New supply	$0.5m									
Wiri West	Land purchase	$0.5m									
Flatbush	Land purchase	$0.5m									
Greenmount	11kV reinforcement	$0.3m									
Chevalier	Second 33/11kV transformer	$0.3m									
Hillsborough	Auto load shifting	$0.3m									
Mt Albert	Auto load shifting	$0.3m									
St Heliers	Auto load shifting	$0.3m									
Browns Bay	11kV reinforcement	$0.2m									
Helensville	11kV reinforcement	$0.2m									
Te Atatu	11kV reinforcement	$0.2m									
Warkworth South	11kV reinforcement	$0.2m									
Liverpool	Protection upgrade	$0.1m									
Liverpool	Protection upgrade	$0.1m									
Keeling Rd	11kV reinforcement	$0.1m									
Wellsford	Voltage regulator	$0.1m									
Henderson Valley	Voltage regulator	$0.1m									
Helensville	Voltage regulator	$0.1m									
Newmarket South	Land purchase		$2.5m								
Westgate	New zone subtation		$2.0m	$6.4m							
Hillsborough	Second 33/11kV transformer & 33kV reinforcement		$1.6m	$1.6m							
Otara	11kV reinforcement		$1.5m								
Maraetai	11kV reinforcement		$1.4m								
Swanson	11kV reinforcement		$1.3m								
Newmarket South	11kV reinforcement		$1.3m								

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Quay	New 110/22kV transformer		$1.0m								
Te Papapa	11kV reinforcement		$0.8m	$0.8m							
Rosebank North	Land purchase		$0.6m								
Mckinnon	11kV reinforcement		$0.5m								
Clendon	11kV reinforcement		$0.4m								
Manukau	11kV reinforcement		$0.4m								
Flatbush	11kV reinforcement		$0.3m	$0.3m	$0.3m	$0.3m					
Waterview	New zone substation			$3.8m	$4.8m						
AIAL	33kV reinforcement			$3.5m	$4.2m						
Liverpool	New 110/22kV transformer			$3.0m							
Red Beach	Second 33/11kV transformer			$1.6m							
Greenmount	11kV reinforcement			$1.6m							
Hobsonville	11kV reinforcement			$1.5m							
Quay	Extend 22kV switchboard			$1.4m							
Takanini	11kV reinforcement			$1.4m							
Warkworth South	New zone substation			$1.0m	$3.0m						
Belmont	11kV reinforcement			$1.0m							
Liverpool	Capacity upgrade			$0.9m	$0.9m						
Balmoral	11kV reinforcement			$0.8m							
Newton	11kV reinforcement			$0.6m	$0.6m						
Quay	Concept study for 110kV switchboard			$0.5m							
Hobsonville East	Land purchase			$0.5m							
Remuera	11kV reinforcement			$0.4m	$0.4m						
Newmarket South	New zone substation			$0.4m	$3.9m	$3.9m					
Rosebank North	New zone substation			$0.4m	$2.3m	$2.3m					
Sandringham	11kV reinforcement			$0.4m	$0.4m						
Hans	11kV reinforcement			$0.4m							
Newton	Auto load shifting			$0.3m							

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Highbury	11kV reinforcement			$0.3m							
Matakana	Land purchase			$0.2m							
Glenvar	New zone substation				$2.0m	$4.8m					
Otara	11kV reinforcement				$1.6m						
Manurewa	11kV reinforcement				$1.4m						
Hobson	Third 110kV transformer				$1.2m						
Warkworth South	11kV reinforcement				$1.0m						
Mangere West	11kV reinforcement				$0.9m						
Quay	Designation & consenting				$0.5m						
Orewa	11kV reinforcement				$0.5m						
Atkinson RD	11kV reinforcement				$0.5m						
Parnell	11kV reinforcement				$0.4m	$0.5m					
Liverpool	22kV reinforcement				$0.4m	$0.4m					
Wainui	Land purchase				$0.4m						
Hobson	Extend 22kV switchboard				$0.2m	$2.2m					
Quay	Civil alterations for 110kV switchboard					$6.0m					
Quay	110kV cable Hobson - Quay					$2.4m					
Kaukapakapa	New zone substation					$2.0m	$2.0m				
Brickworks	Second 33/11kV transformer					$2.0m					
Quay	Customer capacity upgrade					$1.2m	$1.2m				
Warkworth South	11kV reinforcement					$1.0m					
Kumeu	Land purchase					$0.5m					
Manly	11kV reinforcement					$0.5m					
Ellerslie	New zone substation					$0.4m	$4.1m	$4.1m			
Chevalier	11kV reinforcement					$0.3m					
Waiheke	Voltage regulator					$0.3m					
Newmarket South	Concept study for 110kV substation					$0.2m					
Mangere East	11kV reinforcement					$0.1m					

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Quay	110kV switchboard						$10.0m				
Sy Johns	33kV reinforcement						$3.0m	$3.0m			
Victoria	Establish 22kV switchboard						$3.0m				
Sandspit	New zone substation						$2.0m	$4.5m			
Te Atatu	Transformer upgrade						$2.0m				
Takanini South	Land purchase						$0.5m				
Brickworks	11kV reinforcement						$0.4m				
Waiwera	Land purchase						$0.3m				
Takapuna	Second 33/11kV transformer							$2.5m			
Waitakere	New zone substation							$2.0m	$3.4m		
Hobsonville East	New zone substation							$2.0m	$2.5m		
Oratia	11kV reinforcement							$2.0m			
Avondale	11kV reinforcement							$1.5m	$1.5m		
Greenhithe	Second 33/11kV transformer							$1.0m			
Spur Rd	Second 33/11kV transformer							$1.0m			
Flatbush	New zone substation							$0.7m	$8.0m	$11.3m	
Coatesville	Second 33/11kV transformer							$0.7m			
Hobson	11kV reinforcement							$0.7m			
Newmarket South	Designation & consenting							$0.2m			
Hobson West	Designation & consenting							$0.0m	$0.1m	$0.1m	
Quay	Second 110kV cable Hobson - Quay								$5.0m		
Waimauku	33kV reinforcement								$5.0m		
Newmarket South	Civil works for 110kV substation								$4.0m		
AIAL	Customer capacity upgrade								$1.5m	$2.6m	
Takanini	11kV reinforcement								$1.1m		
Takapuna	11kV reinforcement (Taharoto)								$1.0m		
Takapuna	11kV reinforcement (Clifton)								$1.0m		
Takapuna	11kV reinforcement (Kitchener)								$1.0m		

Substation	Project	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21
Mangere Central	11kV reinforcement								$0.9m		
Newmarket South	110kV cable alterations									$10.0m	
Woodford	Second 33/11kV transformer & 33kV reinforcement									$2.0m	$3.2m
Keeling Rd	Second 33/11kV transformer & 33kV reinforcement									$2.0m	$1.9m
Lincoln	Land purchase									$1.0m	
Newmarket	Customer capacity upgrade									$0.8m	$0.8m
Hobson	22kV reinforcement									$0.7m	$0.7m
Greenmount	Fault level management									$0.2m	
Hobson West	110kV switchboard & 2x 60MVA 110/22kV transformers										$10.0m
Hobson West	Civil works for 110kV substation										$6.0m
Quay	Extend 22kV switchboard										$1.6m
Hillsborough	11kV reinforcement										$0.5m

Table 5-43 : Timing and estimated cost of major growth projects until 2020

5.25.1 Network Development Expenditure Forecast

In Table 5-44 the network development expenditure forecast is broken down into broad expenditure categories. Note that customer initiated projects relate to those projects that are significant enough to initiate network reinforcement.

Financial year ending	Jun 12	Jun 13	Jun 14	Jun 15	Jun 16	Jun 17	Jun 18	Jun 19	Jun 20	Jun 21
CBD reinforcements	$23.0m	$17.7m	$9.2m	$4.9m	$13.6m	$16.0m	$3.0m	$8.1m	$3.1m	$20.6m
Customer initiated	$17.4m	$3.5m	$10.1m	$12.8m	$7.3m	$6.7m	$5.5m	$7.9m	$9.7m	$7.1m
Duct provision	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.0m	$2.7m	$2.0m	$2.0m	$2.0m
Feeder reinforcements	$7.0m	$7.9m	$8.1m	$6.1m	$2.6m	$0.4m	$3.5m	$5.6m	$0.0m	$0.5m
Land acquisition	$1.5m	$3.1m	$0.7m	$0.4m	$0.5m	$0.8m	$0.0m	$0.0m	$1.0m	$0.0m
Non-specific feeder reinforcements	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m	$0.9m
Power quality	$0.5m	$0.5m	$0.2m	$0.4m	$0.5m	$0.4m	$0.2m	$0.4m	$0.4m	$0.2m
Sub-transmission reinforcements	$0.0m	$0.0m	$0.0m	$0.0m	$0.0m	$3.0m	$3.0m	$5.0m	$0.0m	$0.0m
Zone substations	$5.7m	$10.9m	$11.7m	$11.2m	$15.6m	$10.1m	$18.7m	$17.9m	$25.3m	$7.6m
Total	$58.0m	$46.5m	$42.9m	$38.7m	$43.0m	$40.3m	$37.5m	$47.8m	$42.4m	$38.9m

Table 5-44 : Expenditure on growth projects to 2021 broken down by major categories ($millions)

The forecast for relocations and overhead improvement projects is provided in Table 5-45.

Financial year ending	Jun-12	Jun-13	Jun-14	Jun-15	Jun-16	Jun-17	Jun-18	Jun-19	Jun-20	Jun-21
Major relocation	$11.1m	$5.9m	$5.8m	$5.4m	$4.7m	$4.7m	$4.7m	$4.7m	$4.7m	$4.7m
Minor relocations	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m	$1.0m
Overhead Improvement programme	$15.6m	$12.6m	$12.6m	$12.6m	$12.6m	$12.6m	$12.6m	$12.6m	$12.6m	$12.6m
Total	$27.7m	$19.5m	$19.4m	$19.0m	$18.3m	$18.3m	$18.3m	$18.3m	$18.3m	$18.3m

Table 5-45 : Expenditure on relocating assets and overhead improvement projects to 2021 broken down by major categories ($millions)

Electricity
Asset Management Plan
2011 – 2021

Asset Maintenance, Renewal and Refurbishment Planning – Section 6

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

6. Asset Maintenance, Renewal and Refurbishment Planning

6.1 Overview

This section covers Vector's life cycle asset maintenance, renewal and refurbishment plans, and the policies, criteria, assumptions, data and processes used to prepare these.

Vector's electricity distribution network is designed and built to deliver electricity to the service level standards set out in the connection agreements with its customers. In order to achieve this level of service at optimum cost, the fixed assets have to be kept in good operating condition. This is achieved by way of renewing (replacing), refurbishing and maintaining assets (regular maintenance). Vector's long-term asset maintenance strategy is to achieve the optimal trade-off between capital expenditure (capex) and operational expenditure (opex), while maintaining a safe, efficient, reliable network. Achieving this requires a balance between effective maintenance and judicious asset renewal.

6.1.1 Vector's Maintenance and Refurbishment Approach

Vector has developed a comprehensive suite of asset maintenance standards that describe its approach to maintaining and refurbishing various asset categories. There are clearly significant differences required in the approach to different asset types, but as a broad rule the maintenance standards provide the following:

- The required asset inspection frequency;
- The routine and special maintenance activities required to be carried out during these inspections; and
- Condition testing that needs to be carried out and the required response to the test results.

In general, Vector's philosophy is to keep its assets in use for as long as they can be operated safely, technically and economically. The maintenance and refurbishment policies support this goal by intervening to ensure optimal performance.

In a small number of cases (such as pole fuses), assets that have low impact on the electricity network's integrity and performance are allowed to run to failure, as the cost of systematically identifying defects to avoid such failures far outweighs the benefits.

6.1.2 Vector's Asset Renewal Approach

Assets are only renewed when (a) assets are irreparably damaged, (b) the operational and/or maintenance costs over the remaining life of the asset will exceed that of replacement, (c) there is an imminent risk of asset-failure and/or (d) assets become obsolete and hence impossible or inefficient to operate and maintain. Asset renewal is therefore in general condition-based rather than age-based.

Optimisation of capital investment and maintenance costs is an important part of Vector's capital investment efficiency drive. This requires comprehensive evaluation of the condition, performance and risk associated with the assets, to provide a clear indication of the optimal time for assets' renewal. Often it may be more efficient to extend the life of asset to beyond normal predicted asset life, by servicing or refurbishing the assets.

Asset condition evaluation is based on:

- Vector's field service providers' (FSPs') surveys, observations, test and defect work schedules; and
- Analysis of equipment test data, such as transformer oil tests, serving tests on cables (checking integrity of outer sheath) and online/offline partial discharge (PD) (test joints and switchgear).

The asset performance evaluation is based on asset fault records and reactive maintenance records.

Once an asset is identified for replacement, Vector's prioritisation methodology is applied to determine the ranking of replacement projects. This methodology is based on assessing the criteria giving rise to the need for replacement, the importance of the asset in question, the impact should the asset fail and the likelihood of such failure. Additional factors considered are the health and safety risk, risk to assets, risk to the company's reputation, potential financial impacts and potential effects on the environment. The final project prioritisation list (that incorporates scoring based on conditions and performance as well as risk assessment), along with budgetary estimates, forms the basis of the annual renewal budgets for each fiscal year.

It is essential to gain and maintain relevant information on the performance of assets in the field in order to undertake accurate assessments. The field data is currently collected and held by our FSPs. At present this data is generally not available in a user-friendly form (it exists mainly as paper-based records, for example). For this reason Vector commissioned a Systems Applications and Processes (SAP) based plant maintenance system during 2010. Following this, asset condition and replacement data is now being directly fed into Vector's databases, based on the activities of our FSPs. Vector has also converted substantial volumes of historical asset performance and replacement records into a database format, to allow these to be assessed together with future field-data. This process is ongoing.

The investigation data, field data and fault records collected and maintained in Vector's databases are increasingly being used to conduct asset condition/performance and risk assessments, informing our renewal programmes.

6.2 Maintenance planning processes, policies and criteria

This section presents the planning processes, policies and criteria for managing Vector's network assets. Vector's strategic focus drives the asset integrity strategies:

Operational excellence

- Ensure the network operation is reliable;
- Ensure network investments and operating activities are efficient;
- Maintain the existing assets in good and safe working order until new assets are built or until they are no longer required; and
- Strive for continual innovation and efficiency improvements on how assets are maintained and operated.

Customer service

- Ensure the safety of the public, our staff and our FSPs;
- Ensure assets are designed, operated and maintained to the required level of standard to provide the agreed level of service ; and
- Ensure an appropriate level of response to customer, concerns, requests and enquiries.

Cost efficiency

- Strive to achieve the optimal balance between capital and operational costs;

- Coordinate asset replacement and new asset creation programmes; and
- Apply innovative approaches to solutions, development and projects execution.

6.2.1 Asset maintenance standards and schedules

Vector's asset maintenance standards are prepared by the Asset Investment (AI) group – in particular by the integrity teams forming part of the engineering group. Asset inspections and maintenance work is carried out by FSPs, under the direction of Vector's Service Delivery (SD) group.

Vector has developed maintenance standards for each major class of assets. The standards form a key part of Vector's schedule for planned maintenance. The purpose of these standards, in conjunction with the schedules of maintenance work, is to ensure assets operate safely and deliver their designed outcomes with regard to life and performance

As part of the asset maintenance standards, the frequency of inspection and reporting per asset category has also been defined. This forms the basis of Vector's asset maintenance schedule.

Vector's maintenance standards are kept on Vector's secure websites and are available to personnel engaged in maintenance activities, as well as for our FSPs. The FSPs must comply with the standards and inspection schedules for each class of assets.

The standards are updated on an "as-you-go basis", so any new findings or updates are incorporated in Vector's standards as soon as they are reviewed by the asset management team, and signed off. Vector's FSPs contribute to, and form an integral part of, this continual improvement process.

Progress against the maintenance schedules and the associated maintenance costs are monitored on a monthly basis. Defects identified during asset inspections are recorded in the contract defects database. FSPs recommend the priorities for the remedial works for defects, which are then reviewed by Vector prior to issuing orders for the work. Maintenance priorities are based on costs, risks and safety criteria.

In making decisions on repairing or replacing the assets Vector will consider recommendations submitted by the FSPs, as well as the factors discussed above. The long-term plans supported by trend analysis for an asset will also be taken into account when assessing whether it should be maintained or replaced.

Vector also undertakes clustering of the projects where they are part of the replacement programme or growth programme of works. If, for example, during inspection or maintenance work, it is found that a large number of defects occur within a specific geographic area where block replacement is planned within the next two years, consideration will be given to carry out the work together as a combined project. Likewise, if new assets are planned to be constructed in a specific area, replacement and/or maintenance work may be deferred for up to two years, if deemed safe. In coordinating such projects long-term savings are achieved due to the economy of scale of projects and potential reduction in establishment and re-establishment costs. Moreover, disruptions to customers and wider public are minimised.

Root cause analysis is normally undertaken as a result of faulty equipment. If this identifies systemic faults or performance issues with a particular type of asset, and if the risk exposure warrants it, a project will be initiated to carry out the appropriate remedial actions on a class of assets. The assets and maintenance standards are also amended to reflect the learning from such root cause analysis.

6.2.2 Maintenance categories

Maintenance works at Vector are categorised in three main categories:

- *Preventive maintenance* is defined by Vector's standards and is work intended to avoid failures before they occur. The frequency of performing the preventative maintenance work (per asset group) is defined in the maintenance standards, flowing through into the contractors' schedule;
- *Corrective maintenance* work is the work that flows from the preventative activities, site inspections, testing and observations by Vector's contractors or any party that reports on potential issues relating to our network's conditions or performance; and
- *Reactive maintenance* work is undertaken following customers' complaints, accidents or any other work that is to rectify damage to the assets caused by unforeseen circumstances.

In addition, Vector also has categories for value added maintenance and for maintenance management services.

The maintenance categories are further explained below.

6.2.2.1 Reactive maintenance

Reactive maintenance is considered to encapsulate all maintenance activities that relate to the repair and restoration of supply, and the safeguarding of life and property. It primarily involves:

- Safety response and repair or replacement of any part of the network components damaged due to environmental factors or third parties interference; and
- Remediation or isolation of unsafe network situations, including immediate vegetation threats, low clearance lines and non-compliant installations.

6.2.2.2 Preventative maintenance

Preventive maintenance covers activities defined through the maintenance standards, and relates to the following:

- Provision of network patrols, inspection and condition detection tasks, sampling and maintenance service work; and
- The coordination of shutdowns and associated network switching and restoration, along with the capture and management of all defined data.

Error! Reference source not found. provides a summary of preventive maintenance activities by asset class, together with appropriate standards document references.

6.2.2.3 Corrective maintenance

Corrective maintenance catches the follow up maintenance repair and component replacement requirements resulting from:

- Assets identified from planned inspections or service work to be in poor condition, requiring repair;
- Poor condition or unserviceable assets identified via one-off coordinated network inspections or identified through proximity capital works;

- Removal of graffiti, painting and repair of buildings and asset enclosures, removal of decommissioned assets, remediation of television interference complaints, one-off type inspection and condition detection tasks outside of planned maintenance standards; and
- Coordination of shutdowns and associated network switching and restoration, along with the capture and management of all defined data.

6.2.2.4 Value-added maintenance

Value-added maintenance activities describe third party directed requests such as the following:

- Issuing maps and site plans to indicate the location of network assets;
- Asset location services, including the marking out of assets, safe work practice site briefings, worksite observer, urgent safety checks, safety disconnections;
- Issuing close approach permits, high load permits, high load escorts; and
- Disconnection and reconnection associated with the property movement of customers and any concerns relating to non-compliance of electricity regulations.

6.2.3 Asset maintenance and field services provider management process

Vector has, through a competitive process, engaged two contractors to maintain its electricity and gas networks. Electrix Ltd is Vector's maintenance contractor for the Northern Region network and Northpower Ltd is Vector's maintenance contractor for the Southern Region network. The maintenance contracts drive the preventative, corrective and reactive maintenance works programmes, based on the requirements set by the Vector maintenance standards.

Both contractors are managed by Vector's SD group. The maintenance contract defines the responsibilities, obligations and key performance indicators (KPIs) to complete scheduled works. Vector's AI group works closely with the SD group to keep abreast of any issues with regards to the contractors' obligations and performance. The maintenance standards form part of the maintenance contract and contractors must comply with them when performing their duties.

Figure 6-1 below describes the flow of work and responsibilities in maintaining Vector's assets.

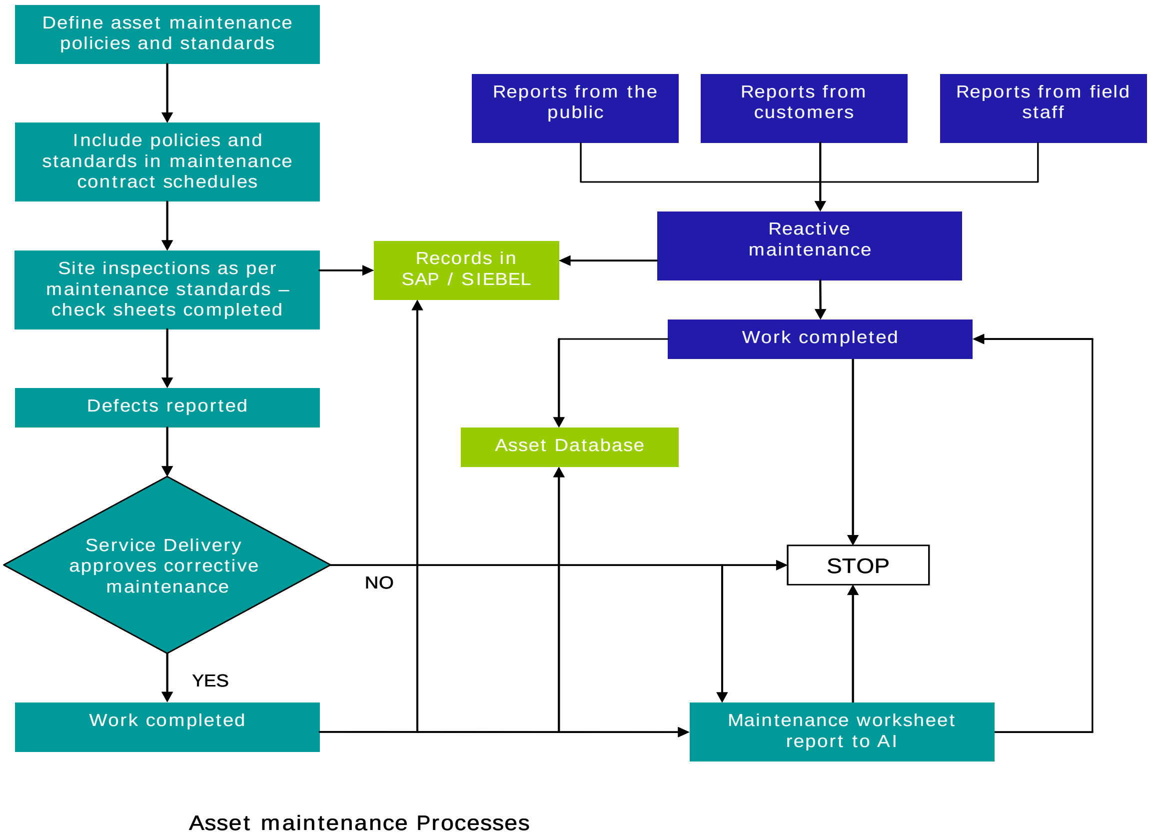


Figure 6-1 : Asset maintenance processes

6.2.4 Forecast maintenance budgets

In the Commerce Commission's Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010 (Input Methodologies) a far more segregated breakdown of maintenance expenditures (actual and forecast) is indicated than for previous AMPs.[1]

For Vector direct maintenance expenditure is a combination of the following internal cost elements:

- **Core maintenance:** Encapsulates all reactive, planned and corrective maintenance activities and services associated with the Northern and Southern network areas. It also includes servicing of the mobile generation units;
- **Value added maintenance:** Provides for customer or retailer recoverable activities, callouts to other utility assets, safety disconnection and following reconnections, voltage quality issues traced to customer assets, vulnerable customer restoration, false callouts, line care services, provision of maps, network mark outs, safety stand-overs, high load permitting and escorts, and asset change over requests from Telecom;
- **Vegetation maintenance:** All reactive, planned and corrective actions associated with distribution assets including substation grounds management, notifications and recovery associated with vegetation management services;

[1] These expenditure category requirements would strictly speaking relate to a customised price-path (CPP) application only. A decision of whether Vector would apply for a CPP is still forthcoming. However, as it is clearly intended that the AMP would be an important supporting document for such an application, Vector has deemed it prudent to incorporate these expenditure categories requirements in the AMP as well.

- **Non-core maintenance:** Contains maintenance activities relating to exceptional and extreme network events, specialist contractor or extraordinary maintenance activities over and above that provisioned through core services. This also includes all reactive, planned and corrective work associated with the Penrose-Hobson tunnel and associated services;
- **Miscellaneous maintenance:** All reactive, planned and corrective activities and services related to the Lichfield network, check metering support and maintenance, road opening notice fees and building warrant of fitness fees associated with the Northern and Southern networks;
- **Inventory related costs:** Includes the warehousing, servicing and management of fault stock, project stock, strategic spares, facilities management of locks, scrap material and distribution transformer refurbishment activities; and
- **Maintenance recoveries:** Cost recovery associated with reactive third party damage activity and capex balancing entry due to the internal capitalisation of assets replaced as the result of faults.

The Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010[2] require a breakdown in the following expenditure categories:

- **Fault and emergency maintenance opex**: Opex principally incurred in responding (by way of undertaking remedial work) to an unplanned instantaneous event that impairs the normal operation of network assets but does not include expenditure on work to prevent or mitigate the impact such an event would have should it occur;
- **Refurbishment and renewal maintenance opex:** Opex that is predominantly associated with the replacement, refurbishment or renewal of items that are asset components;
- **Routine and preventative maintenance opex:** Opex that is predominantly associated with planned work and
  a. Includes:
     - Fault rectification work that is undertaken at a time or date subsequent to any initial fault response and restoration activities;
     - Routine inspection;
     - Testing; and
     - Vegetation management activities; and
  b. Excludes expenditure on initial fault or emergency maintenance;
- **System management and operations opex:** Opex that is predominantly associated with the management and operation of the network including:
  a. System operations;
  b. System studies and planning;
  c. Design;
  d. Network record keeping; and
  e. Standards and manuals.

[2] Ibid.

The Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2010[3] also requires direct maintenance expenditure disaggregation into the following expenditure categories:

a. Assets owned by the Electricity Distribution Business (EDB) but installed at bulk supply points owned by others;

b. Sub-transmission network including power transformers;

c. Distribution network including distribution transformers;

d. Switchgear;

e. Low voltage distribution network; and

f. Supporting or secondary systems including:

   i. Ripple injection plant;

   ii. SCADA;

   iii. Communications equipment;

   iv. Metering systems;

   v. Power factor correction plant;

   vi. EBD-owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and

   vii. Other generation plant owned by the EDB; and

g. Other.

The direct maintenance opex forecast considers all network areas, Northern, Southern and Lichfield, and also combines each of the networks, the four required opex types: (i) Fault and Emergency Maintenance, (ii) Refurbishment and Renewal, (iii) Routine and Preventive, and (iv) System Management and Operations opex per defined asset category.

In Figure 6-2 to Figure 6-5 and Table 6-1 to Table 6-4 a disaggregated breakdown of forecast opex is provided in accordance with the input methodologies' requirements. A gradual (small) increase in opex is anticipated, to reflect the addition of new assets over time. Provision is also made for increased expenditure on distribution switchgear maintenance (refer to Section 6.3.21 for a discussion).

[3] Ibid.

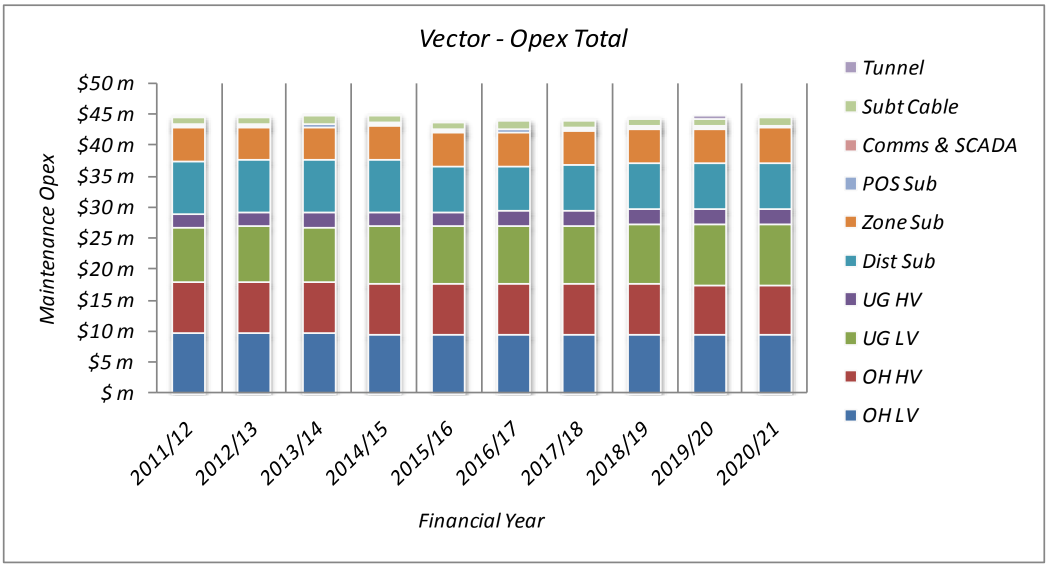


Figure 6-2 : Total disaggregated opex forecast

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$9.57 m	$9.55 m	$9.47 m	$9.39 m	$9.36 m	$9.33 m	$9.30 m	$9.27 m	$9.24 m	$9.21 m
OH HV	$8.31 m	$8.29 m	$8.23 m	$8.21 m	$8.19 m	$8.17 m	$8.15 m	$8.13 m	$8.12 m	$8.10 m
UG LV	$8.77 m	$8.89 m	$9.01 m	$9.14 m	$9.26 m	$9.39 m	$9.52 m	$9.64 m	$9.78 m	$9.91 m
UG HV	$2.20 m	$2.24 m	$2.27 m	$2.30 m	$2.33 m	$2.37 m	$2.40 m	$2.44 m	$2.47 m	$2.51 m
Dist Sub	$8.48 m	$8.45 m	$8.48 m	$8.51 m	$7.29 m	$7.32 m	$7.35 m	$7.38 m	$7.28 m	$7.31 m
Zone Sub	$5.42 m	$5.34 m	$5.37 m	$5.40 m	$5.43 m	$5.47 m	$5.50 m	$5.53 m	$5.56 m	$5.59 m
POS Sub	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m
Comms & SCADA	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m	$0.18 m
Subt Cable	$1.14 m	$1.15 m	$1.17 m	$1.18 m	$1.19 m	$1.21 m	$1.22 m	$1.23 m	$1.25 m	$1.26 m
Tunnel	$0.33 m	$0.33 m	$0.23 m	$0.33 m	$0.23 m	$0.33 m	$0.23 m	$0.33 m	$0.33 m	$0.33 m
Total	$44.74 m	$44.77 m	$44.75 m	$44.98 m	$43.81 m	$44.10 m	$44.19 m	$44.48 m	$44.54 m	$44.74 m

AMP Opex Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Routine & Preventive	$19.70 m	$19.77 m	$19.73 m	$19.90 m	$19.86 m	$20.04 m	$20.01 m	$20.18 m	$20.25 m	$20.32 m
Refurbish & Renewal	$12.04 m	$11.94 m	$11.88 m	$11.87 m	$10.66 m	$10.71 m	$10.75 m	$10.79 m	$10.71 m	$10.75 m
Fault & Emergency	$13.00 m	$13.07 m	$13.14 m	$13.21 m	$13.28 m	$13.36 m	$13.43 m	$13.51 m	$13.59 m	$13.67 m
Total	$44.74 m	$44.77 m	$44.75 m	$44.98 m	$43.81 m	$44.10 m	$44.19 m	$44.48 m	$44.54 m	$44.74 m

Table 6-1 : Total disaggregated opex forecast

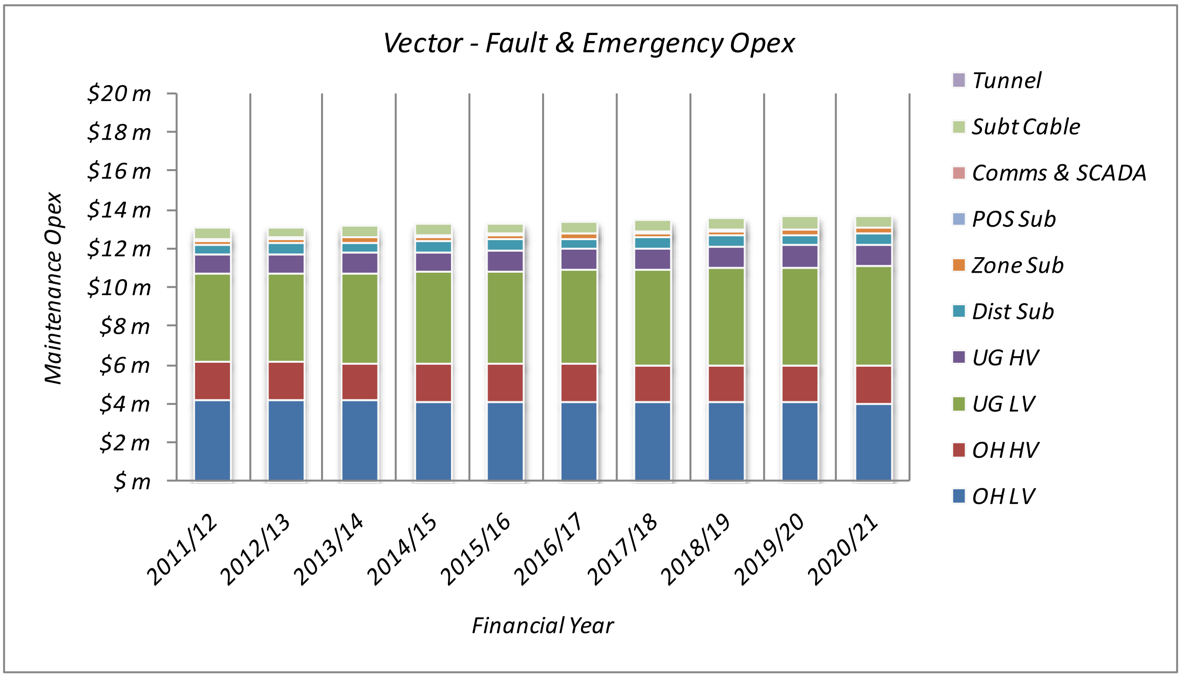


Figure 6-3 : Fault and emergency maintenance expenditure

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$4.15 m	$4.13 m	$4.11 m	$4.09 m	$4.08 m	$4.06 m	$4.04 m	$4.02 m	$4.00 m	$3.99 m
OH HV	$1.96 m	$1.95 m	$1.95 m	$1.94 m	$1.93 m	$1.93 m	$1.92 m	$1.91 m	$1.91 m	$1.90 m
UG LV	$4.52 m	$4.59 m	$4.65 m	$4.72 m	$4.79 m	$4.86 m	$4.93 m	$5.00 m	$5.07 m	$5.15 m
UG HV	$0.99 m	$1.01 m	$1.03 m	$1.04 m	$1.06 m	$1.08 m	$1.10 m	$1.12 m	$1.14 m	$1.16 m
Dist Sub	$0.54 m	$0.54 m	$0.55 m	$0.55 m	$0.55 m	$0.55 m	$0.56 m	$0.56 m	$0.56 m	$0.57 m
Zone Sub	$0.22 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m	$0.23 m
POS Sub	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Comms & SCADA	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m	$0.06 m
Subt Cable	$0.56 m	$0.56 m	$0.57 m	$0.58 m	$0.58 m	$0.59 m	$0.59 m	$0.60 m	$0.61 m	$0.61 m
Tunnel	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Total	$13.00 m	$13.07 m	$13.14 m	$13.21 m	$13.28 m	$13.36 m	$13.43 m	$13.51 m	$13.59 m	$13.67 m

Table 6-2 : Fault and emergency maintenance expenditure

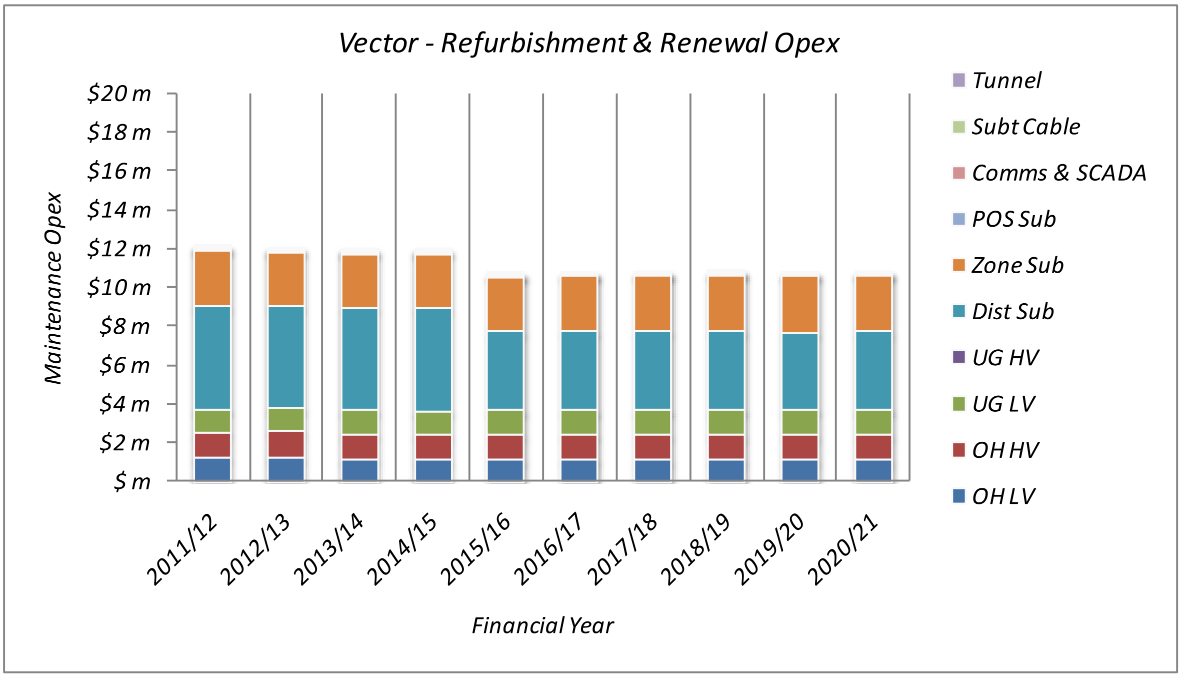


Figure 6-4 : Refurbishment and renewal maintenance expenditure

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$1.18 m	$1.18 m	$1.13 m	$1.08 m	$1.07 m	$1.07 m	$1.07 m	$1.07 m	$1.06 m	$1.06 m
OH HV	$1.34 m	$1.34 m	$1.29 m	$1.29 m	$1.28 m	$1.28 m	$1.28 m	$1.28 m	$1.27 m	$1.27 m
UG LV	$1.19 m	$1.20 m	$1.22 m	$1.24 m	$1.25 m	$1.27 m	$1.29 m	$1.30 m	$1.32 m	$1.34 m
UG HV	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Dist Sub	$5.29 m	$5.25 m	$5.27 m	$5.28 m	$4.05 m	$4.06 m	$4.08 m	$4.09 m	$3.98 m	$4.00 m
Zone Sub	$2.86 m	$2.78 m	$2.79 m	$2.80 m	$2.82 m	$2.83 m	$2.85 m	$2.86 m	$2.88 m	$2.89 m
POS Sub	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m	$0.00 m
Comms & SCADA	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m	$0.08 m
Subt Cable	$0.06 m	$0.06 m	$0.06 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m	$0.07 m
Tunnel	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m
Total	$12.04 m	$11.94 m	$11.88 m	$11.87 m	$10.66 m	$10.71 m	$10.75 m	$10.79 m	$10.71 m	$10.75 m

Table 6-3 : Refurbishment and renewal maintenance expenditure

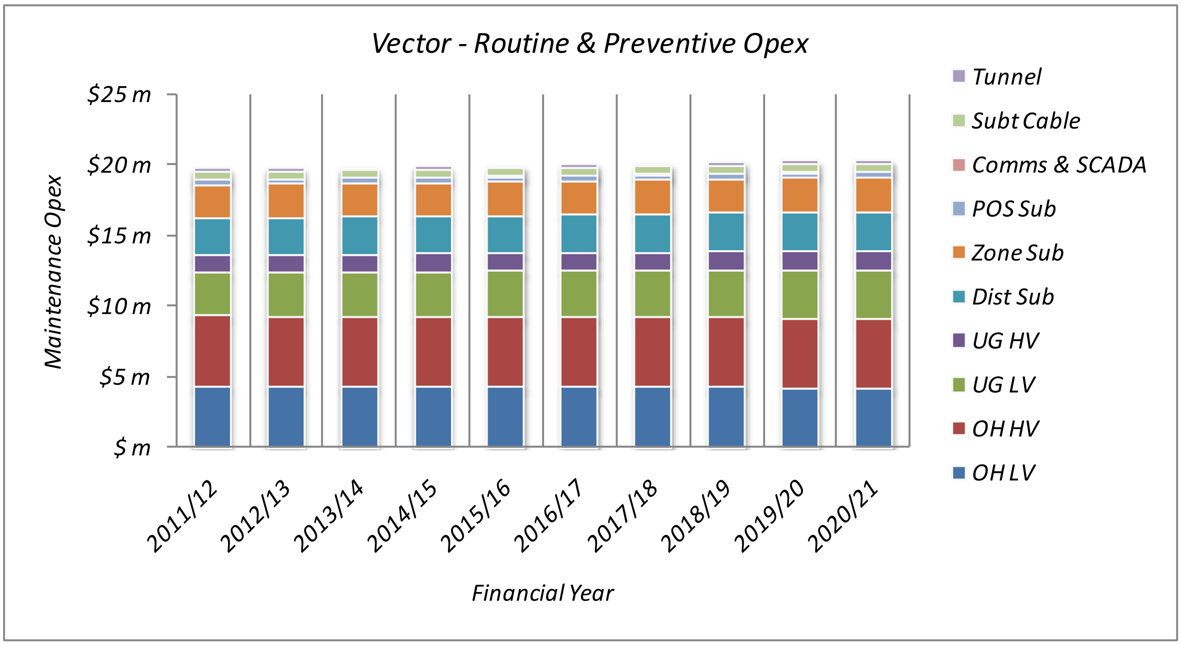


Figure 6-5 : Routine and preventive maintenance expenditure

AMP Category	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
OH LV	$4.25 m	$4.24 m	$4.23 m	$4.22 m	$4.21 m	$4.20 m	$4.19 m	$4.19 m	$4.18 m	$4.17 m
OH HV	$5.01 m	$5.00 m	$4.99 m	$4.98 m	$4.97 m	$4.96 m	$4.95 m	$4.94 m	$4.93 m	$4.92 m
UG LV	$3.07 m	$3.10 m	$3.14 m	$3.18 m	$3.22 m	$3.26 m	$3.30 m	$3.34 m	$3.38 m	$3.42 m
UG HV	$1.21 m	$1.23 m	$1.24 m	$1.26 m	$1.27 m	$1.29 m	$1.30 m	$1.32 m	$1.33 m	$1.35 m
Dist Sub	$2.65 m	$2.66 m	$2.67 m	$2.68 m	$2.69 m	$2.70 m	$2.71 m	$2.72 m	$2.73 m	$2.75 m
Zone Sub	$2.33 m	$2.34 m	$2.36 m	$2.37 m	$2.38 m	$2.40 m	$2.42 m	$2.43 m	$2.44 m	$2.46 m
POS Sub	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m	$0.35 m
Comms & SCADA	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m	$0.04 m
Subt Cable	$0.52 m	$0.52 m	$0.53 m	$0.54 m	$0.54 m	$0.55 m	$0.56 m	$0.57 m	$0.57 m	$0.58 m
Tunnel	$0.29 m	$0.29 m	$0.19 m	$0.29 m	$0.19 m	$0.29 m	$0.19 m	$0.29 m	$0.29 m	$0.29 m
Total	$19.70 m	$19.77 m	$19.73 m	$19.90 m	$19.86 m	$20.04 m	$20.01 m	$20.18 m	$20.25 m	$20.32 m

Table 6-4 : Routine and preventive maintenance expenditure

Vector has a comprehensive preventive maintenance approach across its network asset base. The delivery of all of these maintenance activities in accordance with prescribed maintenance standards (see Table 6-4) is closely monitored and adjusted by SD, on a monthly basis, to ensure the agreed annual target volumes are complied with. Extensive monthly feedback is obtained on actual versus planned progress, KPI performance, causality and issues impacting progress or performance, new risks, action plans and focal points for the coming months. The overall effectiveness of the programme is evaluated by contract KPI performance and the roll up to Vector's corporate performance metrics, of which environmental compliance, public, employee and contractor safety and network SAIDI are the core measures.

6.3 Asset inspection, maintenance, refurbishment and renewal programmes

In this section, the details of Vector's asset inspection, refurbishment and renewal programmes are discussed, broken down per major asset category.

6.3.1 Sub-Transmission cable

The total Vector sub-transmission network consists of 576km of cables operating at 110kV, 33kV and 22kV with a book value of $256 million. A breakdown per cable type is provided in

Table 6-5 below and the age profile per network is indicated in Figure 6-6 and Figure 6-7 below.

Cable Length	110kV	33kV	22kV	Total km
Southern	67 km	257 km	122 km	446 km
Northern	0 km	130 km	0 km	130 km
Total	67 km	387 km	122 km	576 km

Cable Value	110kV	33kV	22kV	Total $m
Southern	$52 m	$104 m	$42 m	$198 m
Northern	$0 m	$58 m	$0 m	$58 m
Total	$52 m	$162 m	$42 m	$256 m

Note: Quantities exclude pole riser lengths of 10 metres per 33 kV and 22kV overhead terminations.

Table 6-5 : Sub-Transmission Cable Population and Book Value

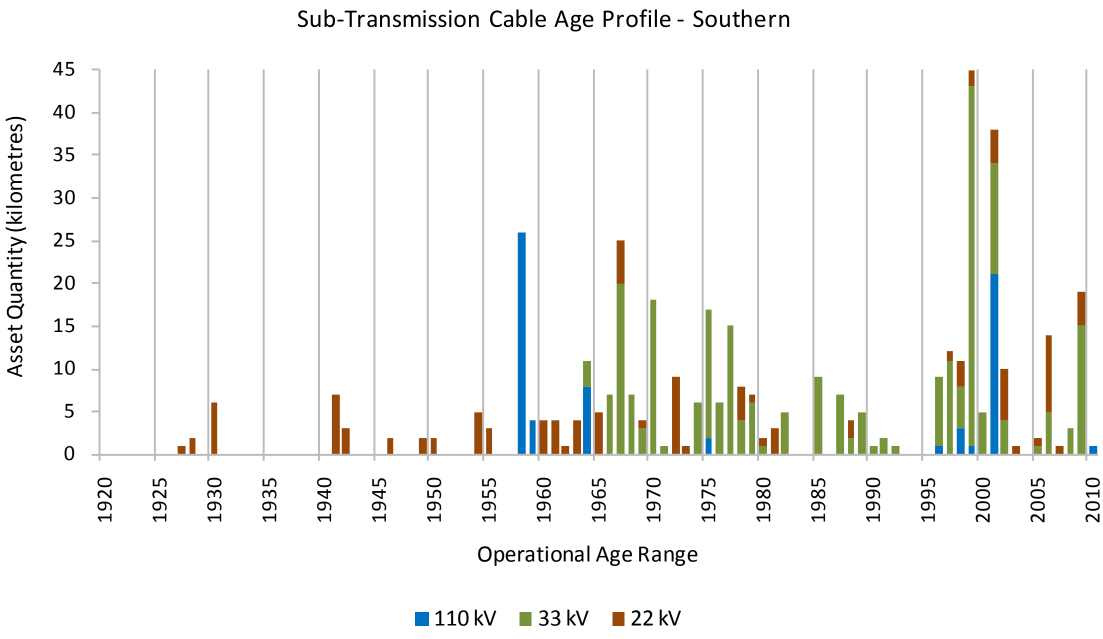


Figure 6-6 : Sub-Transmission Cable Age Profile - Southern

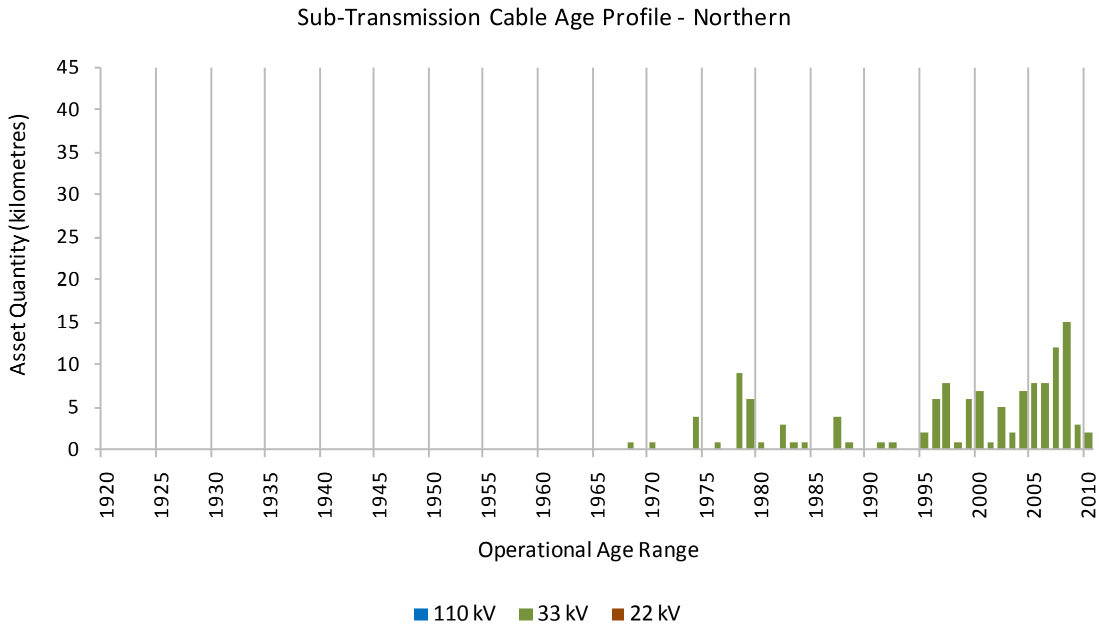


Figure 6-7 : Sub-Transmission Cable Age Profile - Northern

6.3.1.1 Asset Condition by Construction Type:

a. Paper Insulated Lead Cables (PILC)

There is approximately 80km of 22kV and 33kV PILC type cables installed on the Vector network between the early 1920's and late 1980's.

The cables are generally in good to very good condition and any failures are usually the result of old joints that fail or the result of 3rd party damage. A number of the older cables were laid on private property and when faults develop these are proving difficult to access due to concerns raised by the private land owners. These cables will be replaced over the next ten years. Others will be replaced as their failure rate increases or ratings can no longer meet network requirements.

b. Fluid Filled Cables

There is approx 170km of 110kV, 33kV and 22kV fluid filled cable installed on the Vector network with all but 3km on the Southern network. These cables were installed between 1964 and 1990 and are generally in very good condition. All fluid filled cables have their fluid pressure closely monitored and alarmed via the SCADA system to promptly identify and minimise any fluid leaks. Cables subject to excessive fluid loss are scheduled for extra maintenance in order to locate and repair the leaks. Vector's experience is that the majority of leaks occur at joints due to thermo-mechanical movement within the cable or due to ground movement.

A systemic issue has been found with thermal-mechanical movement in the three core aluminium conductor joints on these cables and one cable in particular (Takanini - Maraetai 33kV) will be replaced over the next five years due to its location and fault history. Other joints are X-rayed if they are exposed for any reason, including fluid leak repairs, and are remade if the movement is too severe.

Vector's contractor has a KPI to reduce the fluid loss below certain predetermined values. However, this is sometimes difficult to achieve due to load restraints in getting certain cables out of service. In such cases the leak is managed so the cable can be kept in service for as long as possible without compromising its integrity and risking electrical failure. Figure 6-8 below shows the sub-transmission cable fluid consumption over the past six years.

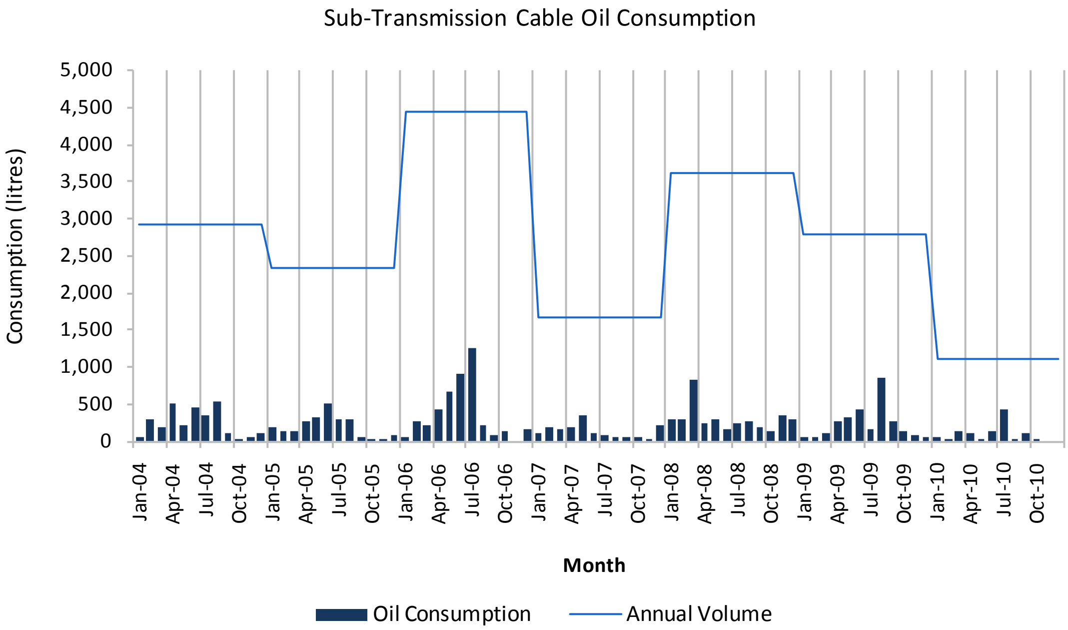


Figure 6-8 : Sub-transmission cable fluid consumption

c. XLPE Cables

There is approximately 310km of 110kV, 33kV and 22kV XLPE installed across Vector's networks. XLPE at sub-transmission level was only introduced onto the Southern network in 1996. As a consequence the problems experienced world-wide with water treeing in the earlier (1960's -70's) cables have been avoided. 181km of these cables are in very good condition. However, five 33kV circuits with possible incorrectly installed joints have caused problems over the past nine years (Risk AIAE3020). All joints on two of these circuits have been replaced. Due to their locations and the back fill material used the joints in the other circuits have not been replaced. Instead they are being closely monitored and tested and will be replaced should their condition deteriorate or fail.

The 128km of 33kV XLPE in the Northern network was installed from 1970 onwards. Due to the nature of the network there are many short sections inserted between sections of overhead lines. These short sections (often no more than one or two spans) cannot be tested economically and are only tested after fault repairs. The maintenance standard requiring serving tests every two years on sub-transmission cable is intended for long sections of continuous cable from the GXP to zone substation or from zone substation to zone substation. However, given the very low fault rate these cables are believed to be in good to very good condition.

d. Gas Pressurised Cables

There are now only four circuits of this gas pressurised cables left on the Southern network. Two of these circuits operate at 110kV and run for 10km each, providing backup to parts of the Auckland CBD. These two circuits are 1958 vintage and the joints, of which there are over 100, are now proving unreliable with a number of failures over the past four years due to pulled ferrules. A project was recently completed to provide an alternative 110kV supply circuit (Liverpool to Quay substation), to ensure Vector's service levels in the CBD can be met without relying on the gas pressurised cables. Final retirement of these cables is scheduled for 2013 when the major supply reinforcement to the CBD (Hobson St GXP, see Section 5) is scheduled to be completed. In the mean time the gas pressurised cables will be kept on standby for additional flexibility run.

The other two gas-filled circuits operate at 22kV, are in good condition and will only be replaced when condition or rating dictate.

6.3.1.2 Maintenance and Testing

The maintenance and testing of sub-transmission cables is covered in Vector's network Standard ENS-0196. Selected circuits are subject to ongoing partial discharge testing, to gain an early indication of any problems. Other circuits are tested in accordance with the routine frequency specified in our standard.

In summary the ENS-0196 defines:

- Routine and preventive maintenance:
  - Weekly – Patrol of cable routes to detect any works or activities that could affect the security or rating of the cables; and
  - Schedule of specific maintenance required on the different cable types and their ancillaries
- Test procedures:
  - High voltage withstand and insulation tests for the various types of cable;
  - Cable serving test;
  - Oil cable pressure system and accessory testing;
  - Gas cable pressure system and accessory testing;
  - Cross-bonding current injection test; and
  - Cable Cover Protection Unit (CCPU or SVL) tests.

6.3.1.3 Replacement programme

The following flow charts in Figure 6-9 to Figure 6-11 give a simplified version of the replacement criteria for each type of cable:

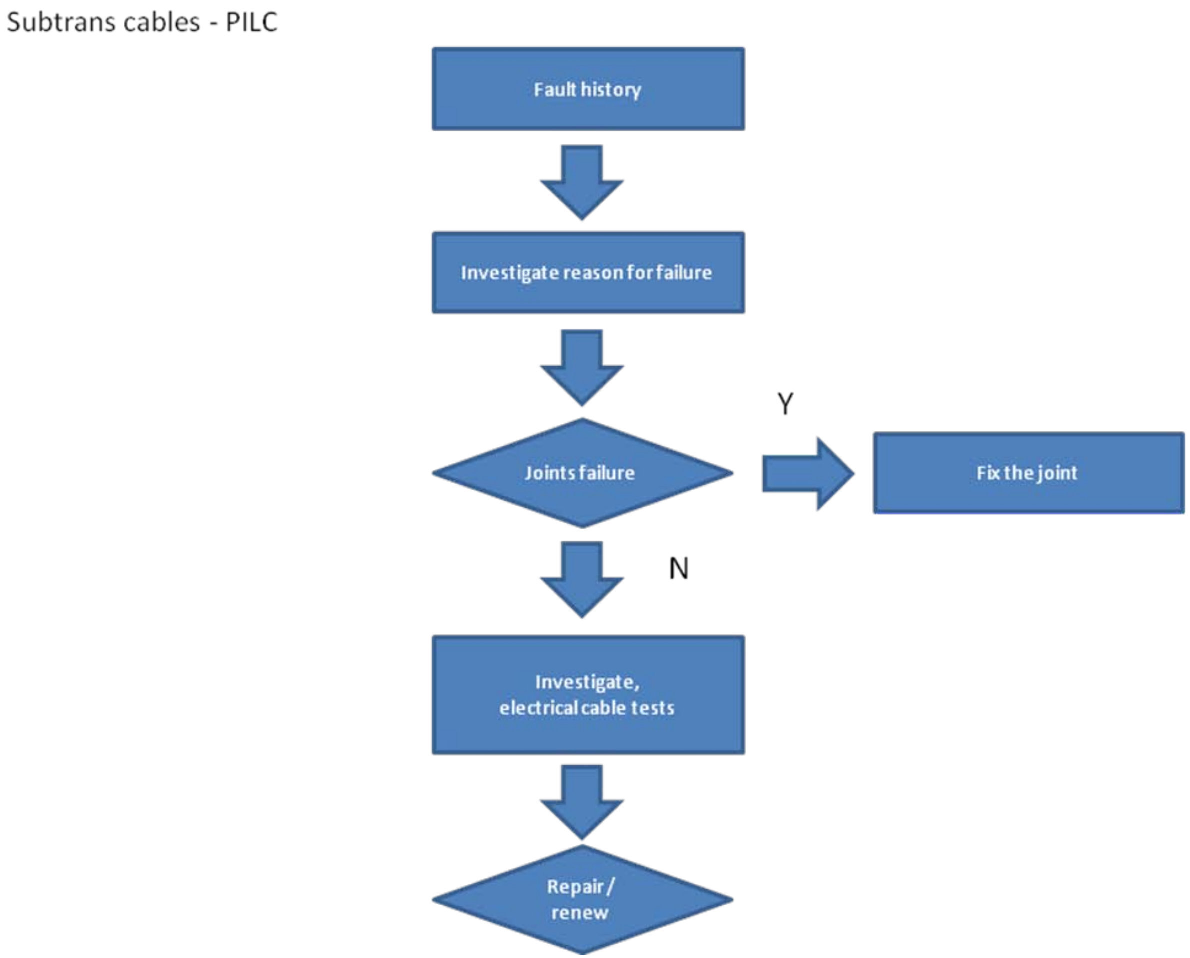


Figure 6-9 : Sub-transmission cables - PILC

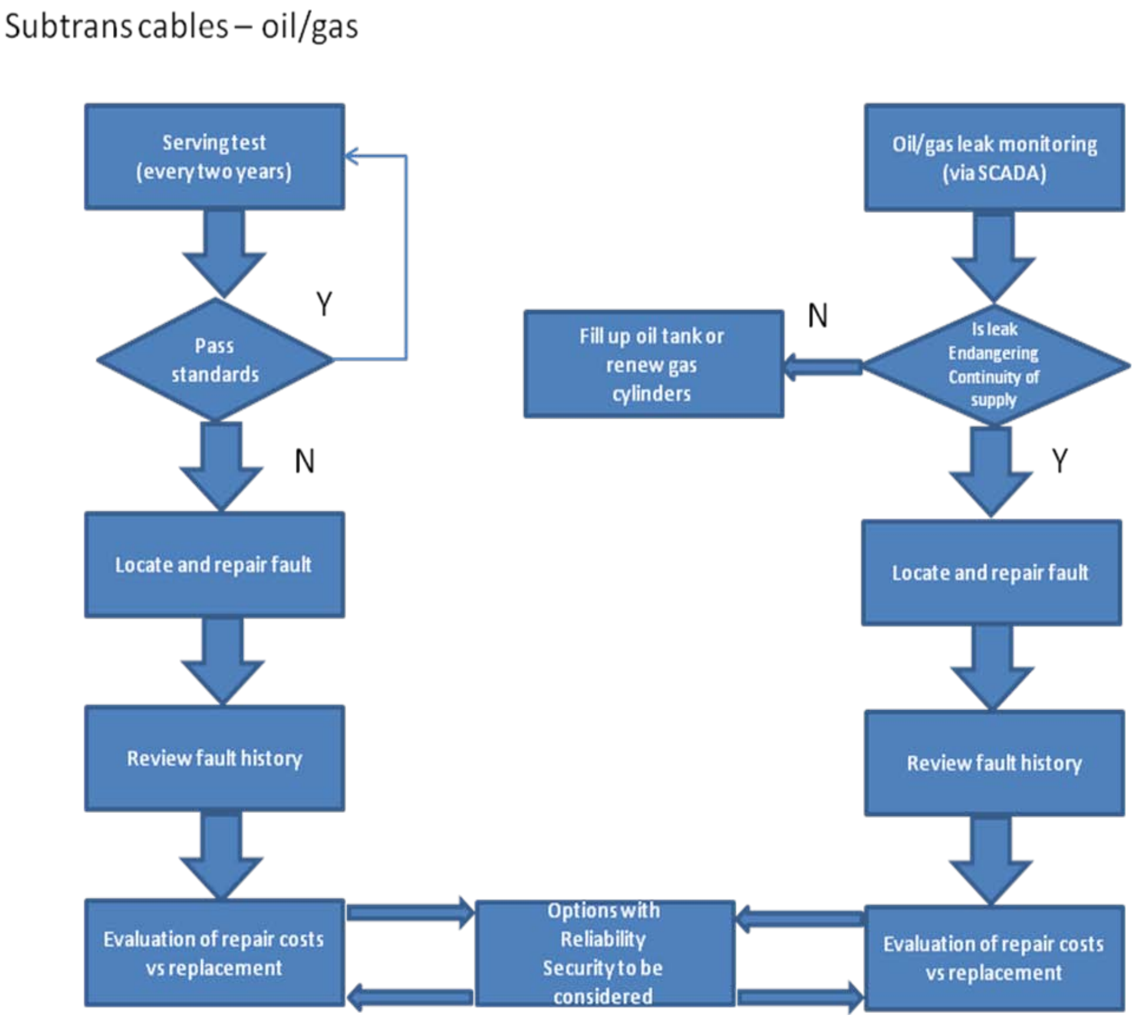


Figure 6-10 : Sub-transmission cables - oil/gas

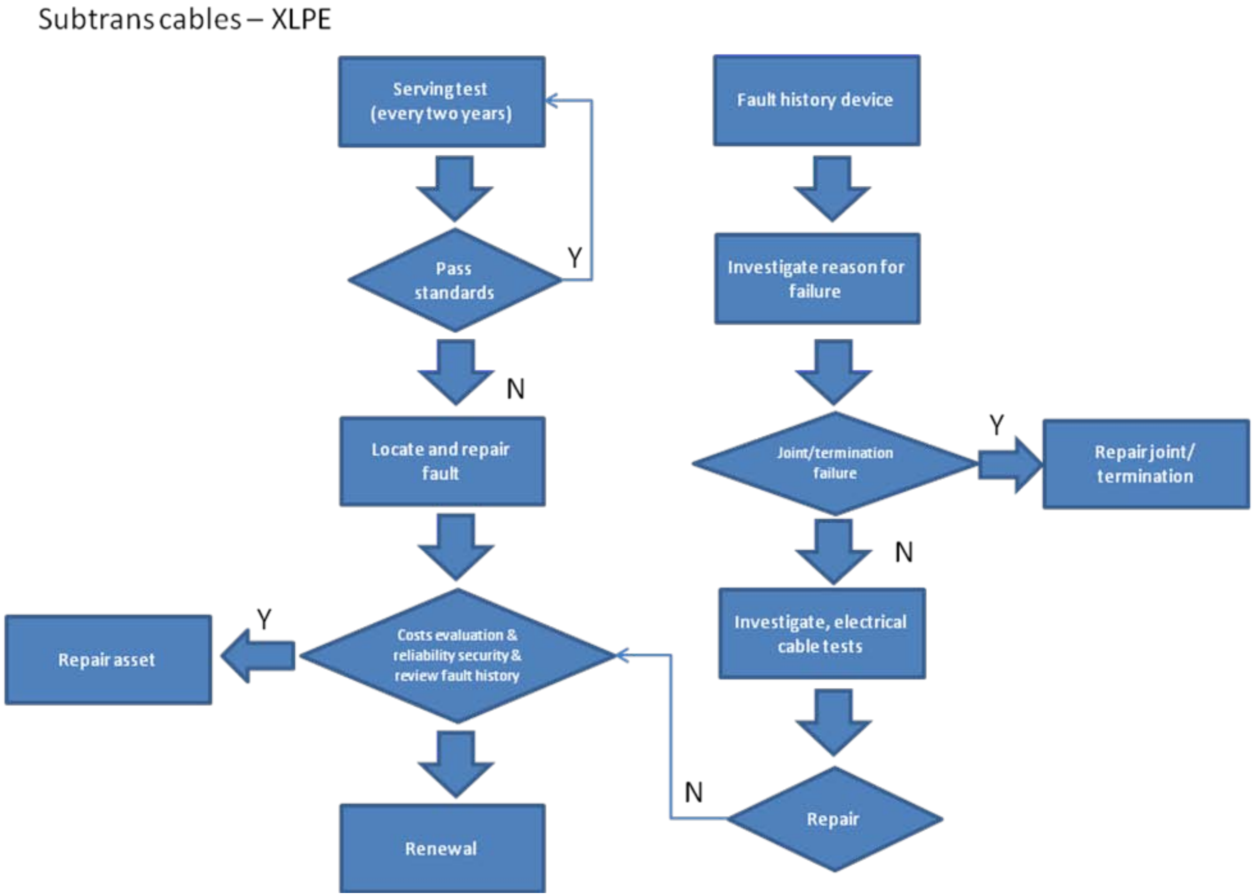


Figure 6-11 : Sub-transmission cables - XLPE

The timing for the replacement of sub-transmission cables is generally based on condition, performance, ratings and industry related failure information. However, it can also result from non-electrically related drivers such as relocation due to other infrastructure development by requiring authorities.

Maintenance history, fault repairs and associated costs to the networks [SAIDI/SAIFI impact] and analysis of risk profiles have identified several cables due for replacement. These circuits represent a significant investment, but keeping them in operation would pose an unacceptable level of risk to the network.[4] A summary of the planned sub-transmission cable replacement projects, taken from the 10 year Programme of Works sheet (subject to ongoing performance measurement), is given in Table 6-6 below.

Asset Description	Circuit Length	Replacement Year	Estimated Cost
Balmoral 22kV	2.0km	2011/12	$7.0 million
Maraetai (FF) 33kV	5.0km	2012/13	$6.0 million
Parnell 22kV	1.8km	2013/14	$3.0 million
Ponsonby 22kV	2.5km	2014/15	$4.0 million
Pt Chevalier 22kV	3.4km	2015/16	$5.5 million
Liverpool–Quay 22kV	2.0km	2016/17	$4.0 million

Table 6-6 : Planned sub-transmission cable replacement projects

The requirement for replacing each of the sub-transmission cables (as described below) is based on analysis of the condition and fault data that is currently available. While the dataset is still incomplete, the analysis is further supported by the experience and observations of Vector's asset specialists. The priority order of replacement is based on indicative condition and failure rates, also taking into account budget requirements and contractor capacity. (The proposed order may change as the asset database is expanded.)

An annual provisional allowance of $5.0 million has been made in the 10-year CAPEX estimate between FY 2017 to 2020 for replacing older PILC cables, which are expected to be approaching the end of their useful life at that stage. More accurate costs estimates for this replacement work will be prepared closer to the time. This allowance is included in the 10 years work programme sheet (Table 6-33).

6.3.1.4 Major sub-transmission cable replacement projects

a. Balmoral 22kV Circuits

These old PILC cables were installed in 1941. The cables have had an increasingly unacceptable fault history over the last 20 years. This problem was temporarily addressed by cutting and turning into Sandringham substation in early 2000 (reducing the extent of reliance on the circuit), but their underlying condition remains poor. The Sandringham feeders which were of the same batch are currently being replaced. In addition, the Balmoral circuits are also under rated for the proposed upgraded transformers at Balmoral substation.

[4] The requirement for replacing the old 22 kV sub-transmission cables was also identified by Siemens GmbH in an assessment carried out by them in 2009 on the robustness of asset management at Vector.

b. Maraetai 33kV Fluid-filled Circuit

This circuit is the last remaining fluid-filled cable at Takanini, commissioned in the late 70's. Due to its location it is subject to continual faults on the overhead line to which it is joined. In addition, because of the peat ground it is buried in, the joints are subject to excessive movement which is problematic for a fluid filled cable. This has already resulted in faulted sections of cable being replaced with overhead line and the replacement and reinforcement of many of the joints. Further faults occur on an ongoing basis and the only economically feasible means of addressing this and to ensure the reliability of supply is to replace the cable.

c. Parnell 22kV circuit

Major sections of these old PILC circuits were laid in 1927. Over the years the cables have not performed very well, but sections of the circuits have over time been replaced (due to road realignment requirements, etc) and as a result the failure rate has dropped off. However, the remaining old sections of cable are now used well beyond their reasonable lives and, based on historical experience, could fail at any time and would be uneconomic to repair. These cables are also under rated for the proposed new transformers at Parnell.

d. Ponsonby 22kV circuits

These circuits consist of one GF (gas filled) 22kV cable installed in 1965 which is one of two remaining gas-filled cables left on the Auckland network. This type of cable technology has gradually been replaced because of the ongoing maintenance issues of leak location and prevention and this cable will need replacing. The other circuit comprises 2x PILC cables installed in 1949-50 and run in parallel. Both these cables are under rated for the existing and any future new transformers.

e. Pt Chevalier 22kV Number 2 circuit

This circuit comprises 2x PILC cables installed in 1930 and run in parallel. They have been the subject of many failures over the years and are now underrated for the new transformers proposed for this substation.

f. Liverpool-Quay 22kV circuit

This project will replace the last remaining gas-filled cable on our network. Given the ongoing 110kV and 22kV reinforcement in the CBD however, this cable may not need direct replacement and could simply be abandoned. A final decision will be made closer to the time.

6.3.2 Power transformers

Vector owns 203 sub-transmission power transformers, including two at Lichfield which lies outside of Vector's main supply network. The transformers have been manufactured by some 16 manufacturers from around the world including ABB, ASEA, AEI, Alstom, BET, Brush, Bonar Long, Fuller, GEC, Hawker Siddeley, OEL, Pauwels, Tyree Power Construction, Wilsons and YET.

The power transformers have a book value of approx $81 million. There are 16 transformers with a primary voltage of 110kV, 144 at 33kV and 43 at 22kV ranging in rating from 5MVA to 65MVA. The majority of these transformers are fitted with on-load tap-changers. Table 6-7 shows the current number of, and value of, power transformers on the networks, categorised by supply side operating voltage.

Population	110kV	33kV	22kV	Total
Southern	11	70	43	124
Northern	3	74	0	77
Total	14	144	43	201

Book Value	110kV	33kV	22kV	Total
Southern	$11 m	$32 m	$15 m	$58 m
Northern	$2 m	$21 m	$0 m	$23 m
Total	$13 m	$53 m	$15 m	$81 m

Table 6-7 : Sub-Transmission Transformers - Population and Book Value

The age profile of the sub-transmission transformers is shown in Figure 6-12 and Figure 6-13.

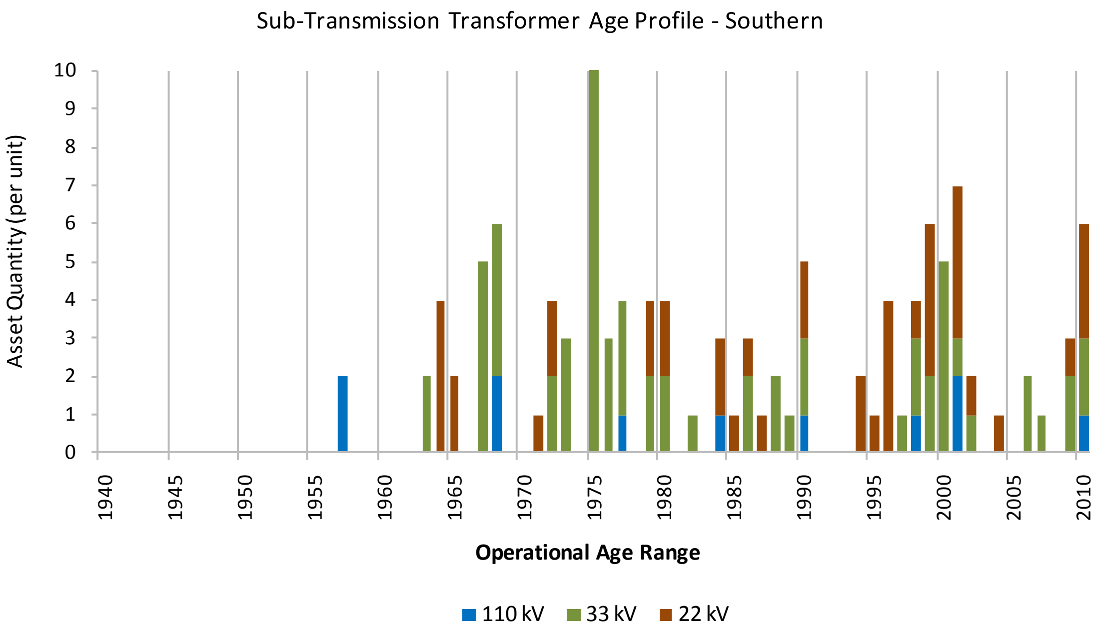


Figure 6-12 : Sub-Transmission Transformer Age Profile – Southern

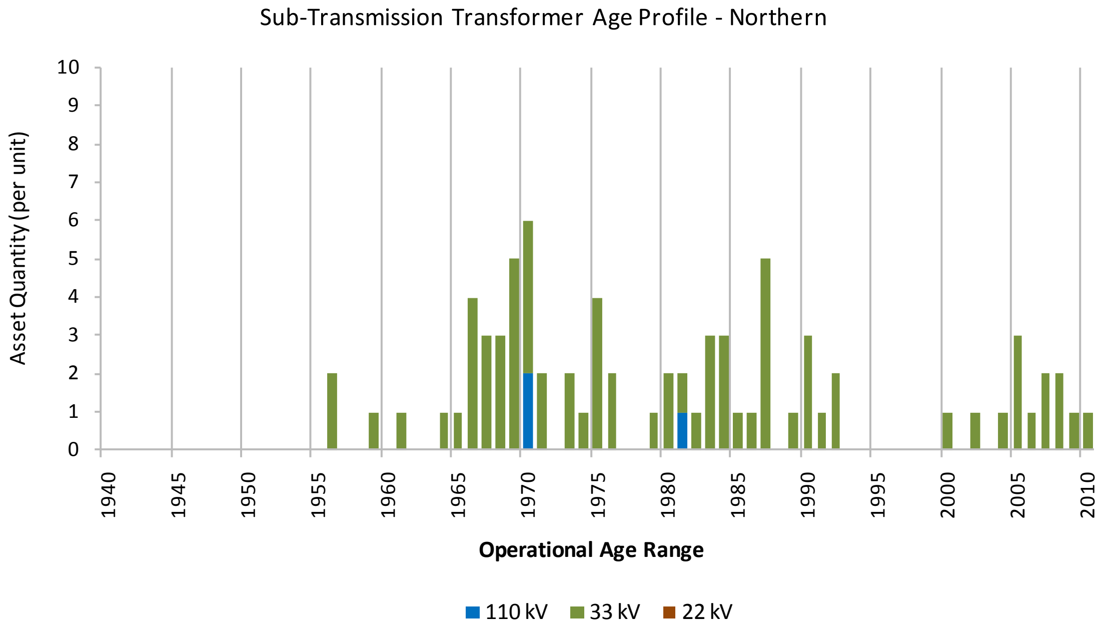


Figure 6-13 : Sub-Transmission Transformer Age Profile – Northern

The following flow chart in Figure 6-14 is a simplified version of the whole condition assessment process.

The normal inspection and maintenance of power transformers is covered in Vector's Network Standard ENS-0193. All intrusive maintenance activity on transformers, including that on the on-load tap changer, is purely condition driven. If off-site refurbishment is deemed necessary this is performed in accordance with Vector's Network Transformer Refurbishment Standard ENS-0164.

In summary the ENS-0193 defines:

- Routine and preventive maintenance:
  - **Annual:** Transformer oil condition sample, transformer condition assessment (TCA) provided by TjH2B covering breakdown voltage, neutralisation value, water content, interfacial tension, dielectric dissipation factor, dissolved gas analysis (DGA), furan analysis required every third year;
  - **Annual:** Tap changer oil condition sample, tap changer activity signature analysis (TASA) provided by TjH2B covering breakdown voltage, neutralisation value, water content, interfacial tension, dielectric dissipation factor, DGA, furan analysis required every third year;
  - **Annual:** Acoustic discharge inspection, thermal camera inspection and PD inspection; and
  - **Bi-monthly:** Visual inspections encompassing tap change mechanism tank, main tank, conservator tank, bushings and insulators, buchholz and pressure relief devices, radiators, heat exchangers, ancillary coolant pumps and motors, instrument and marshalling cubicles, oil and winding temperature gauges, earthing installation, seismic and foundation mounts.

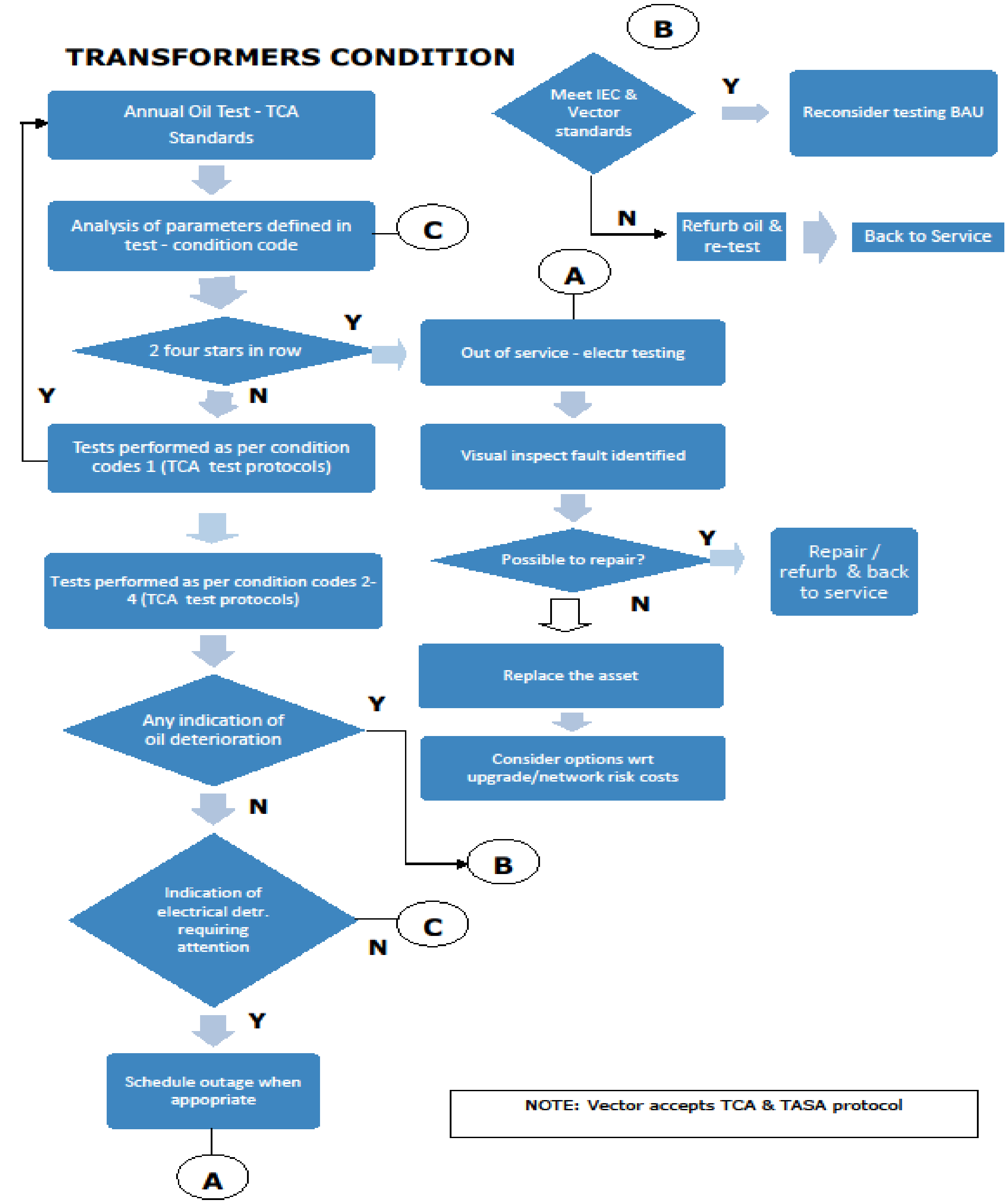


Figure 6-14 : Condition assessment process

- Refurbish and renewal maintenance:
  - Further diagnostic or corrective maintenance service work is triggered on:
    - The oil analysis condition code together with TjH2B recommendations;
    - Identified thermal hotspots greater than ten degrees above surroundings;
    - Levels of acoustic discharge, significantly above background noise; and

  - Levels of PD, significantly above background noise.
- o Diagnostic testing may require:
  - Transformer winding resistance/impedance/insulation resistance/ratio testing, core insulation resistance testing, auxiliary wiring and CT insulation resistance testing, magnetising inrush current testing, bushing and winding insulation power factor and dielectric loss testing.
- o Maintenance servicing may require:
  - Internal tap changer inspection and service;
  - Desiccant replacement;
  - Bushing clean and re-grease; and
  - Bearing and lubricant service of fans, motors and coolant pumps.

6.3.2.1 Power transformer replacement programme

Vector's transformer population is in good condition overall but there are a small number where DP (degree of polymerisation) tests indicate they are coming to the end of their technical life. These are monitored closely.

Vector has experienced two power transformer failures over the last two years where the units had to be written off. Based on recent testing results and past replacement history, the transformers in Table 6-8 have been identified for replacement in the 10 year Programme of Works. Two new power transformers are on order to replace old units at Liverpool substation during FY2011. Table 6-8 below shows the budgeted replacement costs over the next 6 years.

Asset Description	No of Units	Replacement Year	Estimated Cost
Balmoral	2	2012/13	$4.4m
Onehunga	2	2013/14	$4.4m
Mt Albert	1	2014/15	$2.2m
Parnell	2	2015/16	$4.4m
Glenn Innes	2	2016/17	$4.4m
Triangle Rd	2	2017/18	$4.0m
Waimauku	1	2018/19	$2.5m

Table 6-8 : Sub-Transmission Transformer replacement projects by year

The requirement for replacing these transformers is based on analysis of the condition and fault data that is currently available. While the dataset is still somewhat incomplete, this analysis is supported by the experience and observations of Vector's asset specialists. The priority order of replacement is based on indicative condition and failure rates, also taking into account budget requirements and contractor capacity. (The proposed order may change as the asset database is expanded.) As most of the units indicate a weakness in the winding insulation strength there is always a risk a close in fault may cause a complete loss of the transformer at any time and this has been figured into the replacement dates.

a. Balmoral

The existing units were manufactured in 1961 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These units are only 12MVA and will be replaced with our standard 20MVA units to cope with expected future load growth.

b. Onehunga

The existing units were manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These transformers are also extremely noisy, breaching current environmental regulations.

c. Mt Albert

The existing unit was manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

d. Parnell

One transformer failed in 2010 and has an old temporary replacement in its place. The other unit was manufactured in 1964 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

e. Glenn Innes

The existing units were manufactured in 1958 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. These units are only 12MVA and will be replaced with our standard 20MVA units to cope with expected future load growth. While these units are the oldest in the replacement programme they were fully refurbished in the late 1990's to extend their operational life.

f. Triangle Rd

The existing units were manufactured in 1956 and 1961 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels.

g. Waimauku

The existing unit was manufactured in 1959 and recent DP testing indicates the winding insulation is deteriorating to unacceptable levels. This transformer has also been the subject of noise complaints.

6.3.2.2 Operating conditions

The engineering design life of a power transformer is 30 to 40 years. However, provided a unit is not subject to abnormal operating conditions (excess load and high winding temperatures), and is well maintained, this life can often be economically extended to at least 60 years.

The majority of Vector's power transformers are operating at the lower end of the permissible winding temperature range. Therefore, an extended operating life for most units can be expected. Transformer specifications have varied over the years from the very early versions of BS 171 (British Standard) to the latest AS 2374 (Australian Standard) which means different thermal and loading guides have been used. Vector's standard for operating temperatures has established three operating temperatures that should never be exceeded:

Top Oil Temperature	105 ºC
Conductor Hot-spot Temp	125 ºC

Metallic part temperature 135 ºC

To take into account the different transformer designs and operating conditions, oil and winding temperature trips are assigned based on the year of manufacture, and our knowledge of, and comfort with, the cooling systems.

A new condition ranking tool is being developed which will be used to rank the condition of all power transformers across the Network. This will take into account such factors as DP (degree of polymerisation), moisture in insulation, DGA's, oil leaks, age etc and should be in place during the 2011 financial year.

6.3.3 Switchboards and Circuit breakers

The Vector network comprises 110kV, 33kV, 22kV, 11kV and 6.6kV high voltage (HV) and medium voltage (MV) systems. Primary circuit breakers (CBs) and switchboards deployed to operate at these voltage levels are installed inside buildings or in outdoor yards enclosed by security fencing, or both. (This class of equipment does not include distribution switchgear.) All zone substation CBs and switchgear have protection relays to control their operation and are monitored by the Network Operations group (control centre) via SCADA systems.

New switchgear is supplied in compliance with Vector's Electricity Network Standard ENS-0005 for indoor switchboards up to and including 33kV, ENS-0106 for outdoor stand-alone CBs up to 33kV and ENS-0022 for indoor 110kV GIS switchboards. Vector's sub-transmission switchgear comprises oil, SF_6 and resin insulated equipment of varying age and manufacturer. The arc-quenching media used in this equipment include oil, SF_6 and vacuum. The majority of the switchgear is 11kV rated followed by 22kV, 33kV and 110kV. This dissemination generally corresponds to the network topology in that, with increasing system voltage, the fewer devices there are on the network. Table 6-9 shows the current number of and value of CBs on the networks categorised by operating voltage.

Population	110kV	33kV	**22kV**	**11kV**	**6.6kV**	Total
Southern	11	18	95	814	24	962
Northern	0	238	0	431	0	669
Total	11	256	95	1245	24	1631

Book Value	110kV	33kV	22kV	11kV	6.6kV	Total
Southern	$11 m	$0 m	$3 m	$11 m	$0 m	$25 m
Northern	$0 m	$6 m	$0 m	$7 m	$0 m	$13 m
Total	$11 m	$6 m	$3 m	$18 m	$0 m	$38 m

Table 6-9 : Sub-Transmission Switchgear – Population and Book Value

The CBs on the Vector electricity network range from new to over 50 years of age. Further, the CBs consist of a mix of technologies corresponding to the relative age of the equipment. The oil type circuit breakers (OCB) are the oldest on the network followed by SF_6 and Vacuum type. Note that CB type as mentioned here refers to the arc quenching technology incorporated and not the insulation medium which can be compound, oil, solid, air or SF_6 gas.

Figure 6-15 and Figure 6-16 shows the age profile of CB's and switchboards in the Southern and Northern regions.

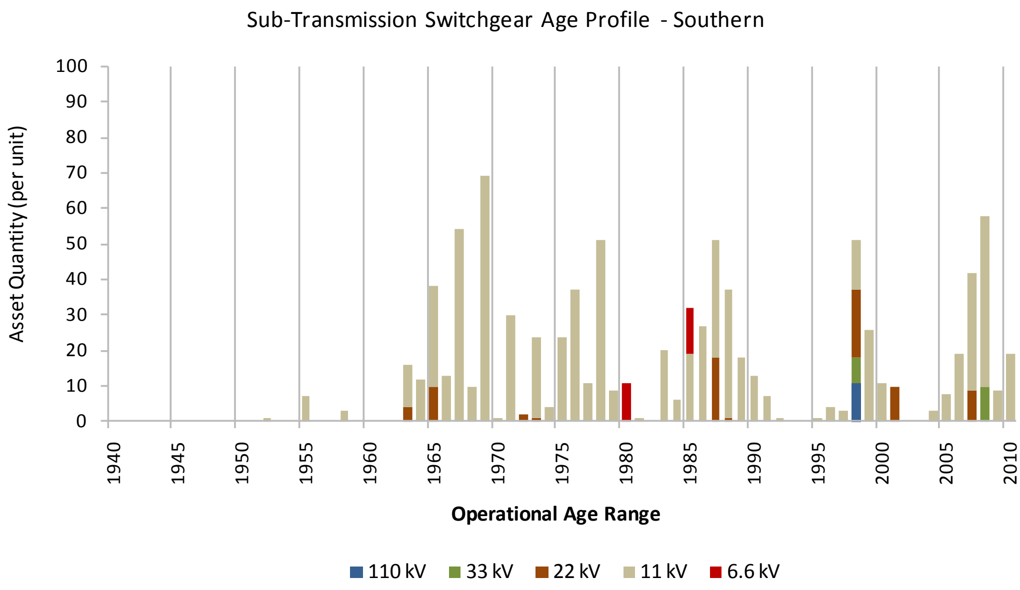


Figure 6-15: Sub-Transmission Switchgear Age Profile – Southern

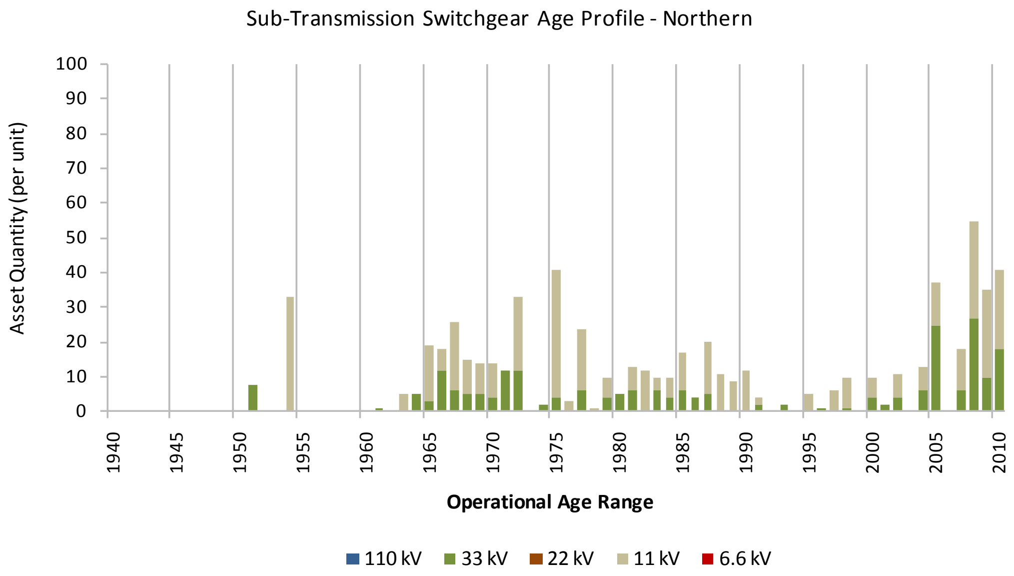


Figure 6-16 : Sub-Transmission Switchgear Age Profile – Northern

The number of CBs on the Vector network is increasing due to the establishment of new zone substations and extensions to existing stations to accommodate load growth, as well as reinforcement projects on the sub-transmission system. The vast majority of CBs are configured as indoor switchboards (consisting of multiple CBs connected to a common bus) the remainder are configured as follows:

- 154 outdoor 33 kV rated CBs and associated air break switches (ABS) and outdoor bus works at Vector zone substations;
- 37 outdoor 33kV rated CBs installed at Transpower GXPs (associated ABS and bus works are owned by Transpower);
- Nine bay 110 kV GIS switchboard at Auckland's Liverpool Substation; and
- Two outdoor 110 kV GIS CBs and associated air break switches (ABS) and outdoor bus works at the Litchfield substation (Fonterra Cheese Factory). Ownership of these two circuit breakers has been assigned to Transpower for the duration of the connection contract.

The oil type circuit breakers are the oldest in the network and constitute 75% of the asset followed by SF_6 at 13% and vacuum at 12%. Circuit breaker technology using vacuum or SF_6 interrupters and SF_6 gas insulated equipment is primarily technology of the last 20 years. Until this time, MOV (minimum oil volume) and bulk oil type circuit breakers dominated the market.

The ODV (optimised deprival value) life for indoor oil-filled equipment is 45 years and for SF_6 and vacuum equipment is 55 years. ODV life for outdoor ABS (air break switch) is 35 years and all outdoor circuit breakers are 40 years regardless of type. This matches reasonably well with Vector's operational experience for this class of equipment.

New equipment purchases must comply with Vector equipment standards ENS-0005 for 11kV to 33kV indoor switchboards, ENS-0106 for 33kV outdoor circuit breakers and ENS-0165 for outdoor air break switches. These equipment standards specify the latest in low maintenance equipment technology.

Depending on the condition of the zone substation building, construction costs to modify existing foundations and buildings can be considerable and need to be evaluated on a station by station basis.

6.3.3.1 Condition of the assets

The SF_6 and Vacuum CBs are the newest in the networks (SF6 breakers are older than the vacuum breakers in the MV class as they were developed ahead of reliable vacuum interrupters). They are in good condition and pose little risk to the network due to modern manufacturing technologies, higher design specifications and compliance with the latest international equipment standards. Even a catastrophic failure in this class of equipment is often restricted to the immediate panel, minimising collateral damage.

The SF_6 CBs pose some environmental concern due to the gas they contain. However, the equipment is designed to be sealed for life and there are gas recovery techniques in the event the equipment requires service. Under normal operating conditions, experience shows only a catastrophic failure of the tank or seals would result in the expelling of gas – a very low probability event.

The oil type CBs are approaching the end of their useful design life and vary anywhere from 40 to 50 years of age. Underrating, failures, mal-operation and lack of spare parts continue to be of concern for this aged equipment. This class of equipment often poses a risk in the event of an explosion. When OCB's fail it can result in fire, explosion and irreparable collateral damage to adjoining or nearby apparatus.

To address these risks, Vector has embarked on a programme to replace the old oil-filled switchgear, as discussed in Section 6.3.3.3.

The oldest technology CBs and switchboards are showing signs of rust, leaking compound and oil, metal fatigue and age related operational concerns. Other apparatus have been shown to have high maintenance requirements or latent defects resulting in earlier than expected replacement and repair programmes.

More modern switchboards with air insulated bus bars and vacuum circuit breakers have proven to be less problematic, as expected with more modern manufacturing's techniques and higher equipment specifications. The metal clad portions, consisting of powder coated galvanised and stainless steel, are not expected to show the same signs of metal fatigue as apparatus that was produced even up to the late 1980's.

New switchboard installations and outdoor CBs of the last six years comply with Vector specifications ENS-0005, ENS-0106 and ENS-0022 and are of maintenance free design. End of life is therefore determined by lifetime fault interruption and normal load switching operations and not traditional time-based estimations. (IEC specification 6227-100 has both electrical and mechanical endurance classifications as part of the standard.) Vector equipment complying with this standard is classed M2 and E2 which equates to extended electrical and mechanical endurance. For primary switchgear the switching mechanism including the interrupter is rated for up to 10,000 mechanical operations and (depending on the manufacturer's interpretation of the standard) up to 100 full fault rated interruptions i.e. 100 operations at 25kA at three seconds.

Vector's numerical protection relays deployed on its switchboards complying to Vector specifications (ENS-0005, ENS-0106 and ENS-0022) are capable of recording fault interrupting data which can be can be used to determine when the switchgear is nearing the end of its operational design life. This information will be used in future asset replacement programmes for switchgear of this type.

6.3.3.2 Maintenance programme

Asset maintenance criteria including inspection, testing and condition assessment is a requirement for each asset. Generic maintenance activities and cycles have been developed for each class of asset but could be applied differently depending on maintenance history and specific industry and manufacturer related information. Vector maintenance standards ENS-0049 and ENS-0188 outline maintenance and testing requirements and intervals for switchboard and circuit breakers. In general, preventative maintenance on Vector's switchgear assets consists of the following:

- All switchgear is visually inspected monthly/quarterly for leaks and general condition, depending on history and type i.e. some circuit breakers require more frequent inspection than others;
- Annual thermographic examination of substation equipment;
- Annual partial discharge testing and monitoring;
- 'Kelman' profile testing and non-invasive partial discharge location and monitoring is carried out on a two year cycle;
- Major maintenance on the switchgear, including inspection and testing of circuit breakers on an eight year cycle and testing of protection relays and systems on a two and four year cycle; and
- Condition assessments either on a scheduled basis or as a result of routine inspection or equipment fault operation.

Through this process of maintenance activities and testing, various CB types have been included in Vector's asset replacement programme. Assets such as indoor 11kV English Electric, Brush and Southwales switchboards and Outdoor 33kV Reyrolle, English Electric and Takaoka circuit breakers have been identified as the next priority replacements. Motorpol supplied 36PV25 (Crompton Greaves) outdoor 33kV CBs as identified in previous AMPs have now all been replaced.

As noted above, new equipment purchased under Vector specification ENS-0022, ENS-0005 and ENS-0106 for growth areas or replacement is maintenance free, fit for life design. Such equipment requires little maintenance activity outside of thermographic survey, PD monitoring and the occasional cleaning of the cabinetry. Existing stations, largely equipped with withdrawable OCB and vacuum circuit breakers (VCBs), will continue to be monitored and maintained on a regular basis.

In summary Vector's standards define:

- Routine and preventive maintenance
    - Annual - Switchboard and associated assets thermal camera inspection;
    - Two yearly - switchboard and associate assets PD assessment;
    - Two yearly - CB timing tests, perform as found/as serviced trip/close operation test, taking accurate time measurement of trip coil current and supply voltage or time measurement of trip coil voltage;
    - Four yearly - outdoor OCB maintenance service, general visual and mechanical inspection, clean external tank, clean bushings, perform as found /as left insulation resistance measurement, check heater operation, clean internal tank, perform as found/as left contact resistance measurements, clean contacts, contact travel and sync assessment, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators functional, control relays or contactors clean, insulating oil replacement, operational cycle checks;
    - Eight yearly - indoor OCB maintenance service, general visual and mechanical inspection, bushing clean, insulation resistance as found/as left testing, check heater function, internal tank clean, contact resistance as found/as left, clean contacts, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators functional, control relays or contactors clean, insulating oil replacement, operational cycle checks;
    - Eight yearly - outdoor vacuum/SF6 CB maintenance service, general visual inspection, external tank clean, bushing clean, insulation resistance as found/as left testing, check heater function, internal tank clean, contact resistance as found/as left, clean contacts, arc-control devices clean, isolating contacts clean and lubricate, trip/close mechanisms clean and lubricate, interlocks and indicators functional, control relays or contactors clean, operational cycle checks;
    - 12 yearly - indoor vacuum/SF6 CB maintenance service; and
    - 16 yearly - switchboard maintenance service, general visual inspection, clean all cubicles, panels and cabinets, clean de-energised spouts and bushings, perform as found/as serviced insulation resistance measurements.

- Refurbish and renewal maintenance
  - o Repair of identified defects are programmed for remediation at a convenient time based on operational importance;
  - o Trip times measured must be within ten percent of previous test results, or satisfactory operation will occur at 70% of rated trip coil voltage. Trip times and spread must be within manufacturer's specified tolerance; and
  - o Any pole contact resistance value must be within 25 percent of remaining pole contact resistance measurements.
- Further diagnostic or corrective maintenance service work is triggered on
  - o Identified thermal hotspots greater than ten degrees above surroundings;
  - o Levels of acoustic discharge, significantly above background noise; and
  - o Levels of PD, significantly above background noise.
- The prescribed maintenance service can be bought forward at any stage based on fault operations and fault magnitude.
- Fault and emergency maintenance
  - o All identified defects that pose an unsafe condition for public and property, equipment operation, substation security, the environment or safety of personnel require immediate repair, replacement or isolation.

6.3.3.3 Refurbishment and replacement programme

The timing for the replacement or refurbishment is based on condition, performance, equipment versus network ratings and industry related information. The timing can also be the result of non-electrically related drivers such as site relocation or decommissioning, safety considerations, building code regulations (e.g. fire protection requirement, seismic compliance) and condition of the existing building (e.g. leaking roofs causing internal faults on the equipment).

To achieve the optimal replacement window requires a balance between risk (reliability and safety) and economic considerations (avoiding unnecessary or early replacement). This requires a fully-fledged switchboard and CB condition based management and replacement strategy, which Vector is continuing to develop and implement.

As noted previously, the continued use of old OCBs on the Vector network is giving rise to a potential safety risk. Some manufacturers (Reyrolle for example) have vacuum retrofit CBs available that can be installed to replace the OCBs. Such retrofits may not lower the incidence of sudden failure due to associated apparatus age and lifetime fatigue, but removing the oil will significantly reduce the collateral damage that can potentially be caused by catastrophic failure. Vector has recently adopted this approach, particularly where significant extensions to the existing switchboards has occurred e.g. Otara substation, which is undergoing a seven panel VCB extension to the existing Reyrolle LMT switchboard. All the OCBs will be replaced with new VCBs to remove the risk to the new apparatus as well as extend the life of the existing switchboard. Vector's VCB retrofit programme will continue with Carbine and Belmont substations slated for VCB retrofits this year followed by Pt. Chevalier which is also undergoing switchboard extension to address growth in its supply area.

Some apparatus is, however, of an age and design that makes retrofitting a non-viable option and these switchboards need to be replaced in their entirety. These switchboards and CBs have been identified and prioritised for replacement.

Due to the age of the existing infrastructure at some substations, the cost of switchboard asset replacement work is estimated to be about $5 million to $7.5 million per annum from now and well into the foreseeable future (estimate includes an allowance for unavoidable but necessary civil and small plant (lighting etc) works. This expenditure will result in the complete replacement (including switchboard, relays, ac/dc supplies, chargers and communications systems) of approximately two to three switchboards per annum.

The process diagram Figure 6-17 below illustrates the thought processes involved in evaluating switchboards and circuit breakers for replacement or refurbishment. Other criteria such as the technology, network growth, criticality and related factors are also used to assist in replacement prioritization.

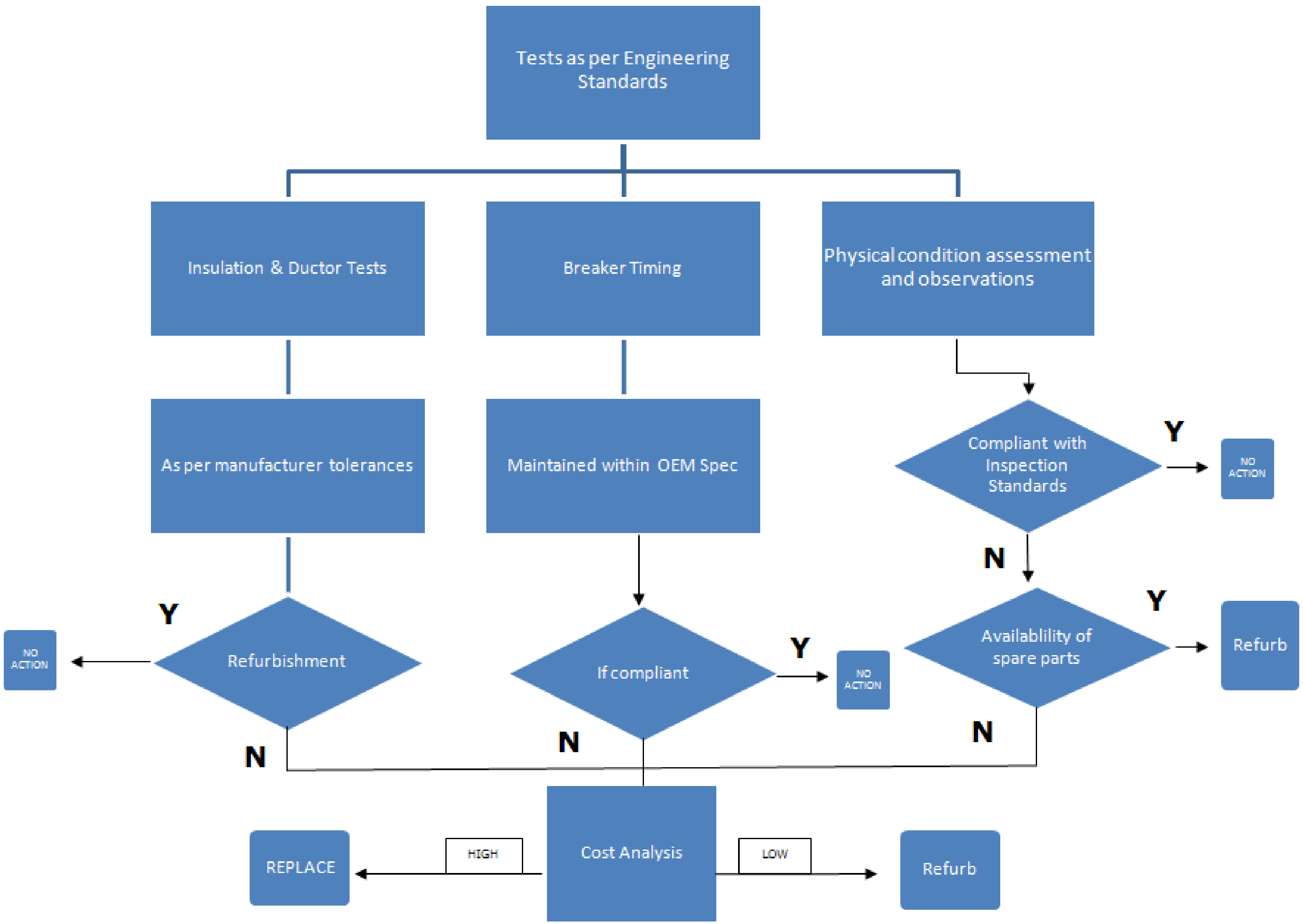


Figure 6-17 : Switchgear replacement decision process

Through the above process a priority programme of works has been established. Table 6-10 below is a summary of the switchboards and CBs identified for replacement in the 10-year programme of works.

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
Southern	Liverpool	11kV Indoor SWBD Replace - Liverpool Stage I (Brush 1965 -28 Panels DOUBLE Bus)	2010/11	$0.10 m	Stage1 - Design Input report and scope of works with option analysis	The 11kV switchboard at Liverpool is one of oldest (manufactured 1965) Brush type switchboards supplying the CBD. Many years ago it was upgraded to 11kV from 6.6 kV. This particular equipment has not been in production for over 20 years and there are very few parts for this DOUBLE BUS configured type of oil-filled apparatus. This switchboard has consistently exhibited significant signs of Partial Discharge during annual surveys with visible rust, oil leaks and sign of past failures in the cable boxes indicating compromised mechanical and electrical systems. This switchboard is critical to the 11kV supplies of the CBD and has significant risk should the switchboard fail. Failure would be likely to involve at least half the switchboard as past Vector experience has shown when this class of oil apparatus fails, replacement is the most economic long-term solution considering the criticality to the CBD.
Southern	Liverpool	11kV Indoor SWBD Replace - Liverpool Stage II (Brush 1965 -28 Panels DOUBLE Bus)	2011/12	$3.00 m	Stage2 - Procure all equipment	
Southern	Liverpool	11kV Indoor SWBD Replace - Liverpool Stage III (Brush 1965 -28 Panels DOUBLE Bus)	2012/13	$2.50 m	Stage3 - Installation, commissioning and all civil works	
Southern	Maraetai	11kV Indoor SWBD Replace - Maraetai (Southwales 1955 - 11 Panels)	2012/13	$1.75 m		The 11kV switchboard at Maraetai is one of many Southwales C4 type oil switchboard on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution. A seismic study of the building carried out in 2010 has been completed. Recommended works are minor to bring the building up to seismic compliance. This study has reduced the cost

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						estimate from the previous amp which included contingency for the construction of new building.
Southern	Onehunga	11kV Indoor SWBD Replace - Onehunga (Southwales 1963 - 12 panels)	2013/14	$1.50 m		The 11kV switchboard at Onehunga is one of many Southwales C4 type oil switchboard on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Balmoral	11kV Indoor SWBD Replace - Balmoral (Brush 1964-12 Panels)	2013/14	$1.50 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Orakei	11kV Indoor SWBD Replace - Orakei (Brush 1966)	2014/15	$2.10 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Manurewa	11kV Indoor SWBD Replace / Retrofit - Manurewa (replace Brush	2015/16	$2.10 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
		1967 - 13 Panels - Retrofit 7 Reyrolle LMT to LMVP)				on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound-filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Kingsland	22kV Indoor SWBD Replace - Kingsland (AEI 1963 DBL Bus) Stage I	2011/12	$0.10 m	Stage1 - Design Input report and scope of works with option analysis	The AEI (1963) 22kV switchboard at Kingsland is the only one of its kind on the network. During scheduled maintenance 3 years ago, many internal bushing clamp had to be replaced due to breakage caused by fatigue. This particular equipment has not been in production for well over 35 years and there are no spare parts. Failed parts have to be remanufactured at considerable expense and downtime. This DOUBLE BUS configured switchboard is critical to the CBD 22kV network. Replacement is the only long-term solution considering the criticality to the CBD.
Southern	Kingsland	22kV Indoor SWBD Replace - Kingsland (AEI 1963 - DBL Bus) Stage II	2012/13	$2.00 m	Stage2 - Procure all equipment	
Southern	Kingsland	22kV Indoor SWBD Replace - Kingsland (AEI 1963 - DBL Bus) Stage III	2013/14	$1.00 m	Stage3 - Installation, commissioning and all civil works	
Southern	Drive	11kV Indoor SWBD Replace - Drive (Brush 1968/Southwales - 13 panels)	2016/17	$1.50 m		This SWBD is comprised of both Brush and Southwales OCB (50/50). Both types are on the scheduled replacement programme of works for reasons already mentioned
Southern	Hobson	11kV Indoor SWBD - Hobson (Brush 1969 - 21 Panels DOUBLE Bus)	2014/15	$2.50 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. After Liverpool, this is the only other DOUBLE BUS configure Brush Switchboard and is unique on the network (LP is an earlier version)This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Freemans	11kV indoor SWBD Replace - Freemans (Brush	2016/17	$1.50 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
		1967-13 panels)				parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Mangere Central	11kV Indoor SWBD Replace - Mangere Cent (Brush 1967 - 15 panels)	2017/18	$1.75 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Pakuranga	11kV Indoor SWBD Replace - Pakuranga (Brush 1969 - 13 Panels)	2018/19	$1.75 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Sandringham	11kV Indoor SWBD Replace - Sandringham (Brush 1967 - 18 Panels)	2019/20	$2.00 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
Southern	Manurewa	11kV Indoor SWBD Replace - Manurewa (Brush 1969 - 13 Panels)	2015/16	$2.10 m		This is one of many 11kV Brush type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. Due to the compound filled bus and bus chambers the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Southern	Avondale	11kV Indoor Switchboard Reyrolle Retrofit	2011/12	$0.55 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Budget does not include P&C (project management and capital carrying) cost of costs
Southern	Carbine	11kV Indoor Switchboard Reyrolle Retrofit	2010/11	$0.55 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Otara	11kV Indoor Switchboard Reyrolle Retrofit	2010/11	$0.20 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Chevalier	11kV Indoor Switchboard Reyrolle Retrofit	2011/12	$0.55 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Hans	11kV Indoor Switchboard Reyrolle Retrofit (10 Panels)	2013/14	$0.50 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Greenmount	11kV Indoor Switchboard Reyrolle Retrofit (2 panels)	2013/14	$0.10 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Hobson	11kV Indoor Switchboard Reyrolle Retrofit (15 Panels)	2014/15	$0.75 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Howick	11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)	2015/16	$0.65 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
Southern	Mt Albert	11kV Indoor Switchboard Reyrolle Retrofit (5 Panels)	2016/17	$0.25 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Manurewa	11kV Indoor Switchboard Reyrolle Retrofit (7 Panels)	2015/16	$0.35 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Manukau	11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)	2016/17	$0.65 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Quay	11kV Indoor Switchboard Reyrolle Retrofit (9 Panels)	2017/18	$0.45 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Rockfield	11kV Indoor Switchboard Reyrolle Retrofit (12 Panels)	2018/19	$0.60 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	St Heliers	11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)	2018/19	$0.65 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	South Howick	11kV Indoor Switchboard Reyrolle Retrofit (12 Panels)	2019/20	$0.60 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Takanini	11kV Indoor Switchboard Reyrolle Retrofit (10 Panels)	2019/20	$0.60 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Southern	Tepapapa	11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)	2020/21	$0.65 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
Southern	Wiri	11kV Indoor Switchboard Reyrolle Retrofit (15 Panels)	2020/21	$0.75 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Belmont	11kV Indoor Switchboard Reyrolle (9 panels) Retrofit	2010/11	$0.45 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Birkdale	11kV Indoor Switchboard Reyrolle (11 panels) Retrofit	2012/13	$0.55 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Henderson Valley	11kV Indoor Switchboard Reyrolle (10 Panels)Retrofit	2013/14	$0.50 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Hillcrest	11kV Indoor Switchboard Reyrolle (12 Panels) Retrofit	2014/15	$0.60 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Brickworks	11kV Indoor Switchboard Reyrolle (LMT 6 Panels)-Station Rebuild	2012/13	$3.00 m	New Building required due to Seismic constraints	Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards.
Northern	Hillcrest	11kV Indoor Switchboard Reyrolle (13 Panels) Retrofit	2015/16	$0.65 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	East Coast Rd	11kV Indoor Switchboard Reyrolle (7 Panels) Retrofit	2015/16	$0.35 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Highbury	11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit	2016/17	$0.25 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Ngataringa Bay	11kV Indoor Switchboard Reyrolle (7 Panels) Retrofit	2016/17	$0.35 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Northcote	11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit	2017/18	$0.25 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Orewa	11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit	2017/18	$0.25 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Woodford	11kV Indoor Switchboard Reyrolle (6 Panels) Retrofit	2018/19	$0.30 m		Continued program of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	Sabulite	11kV Indoor Switchboard Replace - Southwales 1963 (11-panels)	2013/14	$1.10 m		Continued programme of removing the risk present by aged oil type circuit breakers from indoor switchboards by replacing the circuit breakers with Vacuum retrofits. This programme provides up rated breakers, behind close door racking (safety of operations) and life extension to existing aged Reyrolle switchboards. Cost estimate does not include P&C costs
Northern	New Lynn	11kV Indoor Switchboard Replace - Southwales 1954	2013/14	$2.30 m	New Building required due to	The 11kV switchboard at New Lynn is one of many Southwales C4 type oil switchboard on the northern and

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
		(11 Panels) station rebuild			Seismic constraints	southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Browns Bay	11kV Indoor Switchboard Replace - English Electric 1954 (10 Panels)	2013/14	$1.80 m		The 11kV English Electric is the last of its kind on the network. Several spare panels have been recovered from previous replacment works so there are adequate spare parts. This SWBD suffered a major internal fault a few years ago resulting in an exploded circuit breakers and damaged bus. This switch is mechanically compromised and has to be replaced.
Northern	Riverhead	11kV Indoor Switchboard Replace -Southwales 1967 - 12 Panels	2012/13	$1.30 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Milford	11kV Indoor Switchboard Replace - Southwales 1967 - 5 Panels	2014/15	$1.00 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution. (NOTE: further analysis required, there may be an opportunity for a Distribution Class equipment solution

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						costing approximately $550,000)
Northern	Balmain	11kV Indoor Switchboard Replace - Southwales 1967 - 5 Panels	2014/15	$1.00 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution. (NOTE: further analysis required, there may be an opportunity for a Distribution Class equipment solution costing approximately $550,000)
Northern	Laingholm	11kV Indoor Switchboard Replace - Southwales 1969 - 11 Panels	2015/16	$1.10 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Wairau Valley	11kV Indoor Switchboard Replace - Southwales 1979 - 11 Panels	2016/17	$1.20 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Hobsonville	11kV Indoor Switchboard	2017/18	$1.20 m		This 11kV switchboard one of many Southwales type oil

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
		Replace - Southwales 1975 - 11 Panels				switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Laingholm	11kV Indoor Switchboard Replace - Southwales 1969- 10 Panels	2018/19	$1.20 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Swanson	11kV Indoor Switchboard Replace - Southwales 1976- 10 Panels	2019/20	$1.20 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.
Northern	Torbay	11kV Indoor Switchboard Replace - Southwales 1975- 5 Panels	2019/20	$1.00 m		This 11kV switchboard one of many Southwales type oil switchboards on the northern and southern networks. There are limited spare parts for this type of oil-filled apparatus. Condition reports on this and many other switchboards are showing signs of deteriorated condition due to long in service life. The design of the insulation systems cannot be easily repaired or enhanced. This equipment has not been in production for many years and replacement is the most economic long-term solution.

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						(NOTE: further analysis required, there may be an opportunity for a Distribution Class equipment solution costing approximately $550,000)
Northern	Wairau Valley	33kV Indoor Switchboard Renewal - Wairau Valley	2010/11	$1.50 m	Station design and site prep works	The 33kV outdoor Switchyard is being redevelopment as part of Transpower's North Auckland and Northland Grid Upgrade (NAaN) projects. This investment represents the design, construction and installation of new indoor 33kV switchboard and switchroom building.
Northern	Wairau Valley	33kV Indoor Switchboard Renewal - Wairau Valley	2011/12	$6.65 m	Building construction , equipment purchase, installation	The 33kV outdoor Switchyard is being redevelopment as part of Transpower's North Auckland and Northland Grid Upgrade (NAaN) projects. This investment represents the design, construction and installation of new indoor 33kV switchboard and switchroom building.
Northern	Wairau Valley	33kV Indoor Switchboard Renewal - Wairau Valley	2012/13	$0.75 m	Commissioning and finish works	The 33kV outdoor Switchyard is being redevelopment as part of Transpower's North Auckland and Northland Grid Upgrade (NAaN) projects. This investment represents the design, construction and installation of new indoor 33kV switchboard and switchroom building.
Northern	Wellsford	33kV Outdoor CB Replace - (2x Reyrolle ORT2)	2012/13	$0.50 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.
Northern	Belmont	33kV Outdoor Circuit Breaker Replace 2x Eng.E. OKW3	2011/12	$0.50 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.
Northern	Helensville	33kV Outdoor CB replace (2 x Reyrolle ORT2)	2013/14	$0.50 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers

Region	Substation	Project	Programme Work	Estimate	Comments 1	Comments 2
						are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.
Northern	Balmain	33kV Outdoor Circuit Breaker Replace 1x Eng.E. OKW3	2014/15	$0.25 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.
Northern	Browns Bay	33kV Outdoor Circuit Breaker Replace (2x Takaoka)	2018/19	$0.50 m		Programme initiation to replace outdoor 33kV bulk Takaoka. These breakers the next most aged bulk oil breakers which are showing signs of age related deterioration. There are currently no spares. These breakers are becoming uneconomic to maintain.
Northern	Waikaukau	33kV Outdoor Circuit Breaker Replace (3 x Nissin KOR)	2017/18	$0.75 m		Programme initiation to replace outdoor 33kV bulk Nissin. These breakers the next most aged bulk oil breakers which are showing signs of age related deterioration. There are currently no spares. These breakers are becoming uneconomic to maintain.
Northern	Waike	33kV Outdoor Circuit Breaker Replace 1x Eng.E OKW3	2016/17	$0.25 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.
Northern	Highbury	33kV Outdoor Circuit Breaker Replace 1x Eng.E OKW3	2012/13	$0.25 m		Continued programmed replacement of aged outdoor 33kV bulk Reyrolle and English Electric Circuit breakers. These breakers are slow to operate, rusting and require intensive maintenance after every fault operations. These breakers are uneconomic to maintain and are in aged and in deteriorated condition with no spare parts.

Table 6-10 : Scheduled switchgear replacement

Beyond this identified programme of works a provisional CAPEX allowance has been made for the financial years from 2017 to 2021, based on our expectation that other switchgear units on the network will demonstrate similar life-cycle performance to those currently being replaced, and units will therefore be reaching the end of their useful lives by then. The actual units to be replaced and the more accurate cost estimates for this will be determined closer to the time. This allowance is included in the ten years work programme sheet (Table 6-33).

Looking at the programme of works over the next ten year period in Figure 6-18 below, a trend appears. Vector is not unusual in the industry in that there exhibits a "Bow Wave" of asset replacement works. Significant growth in electrification of the 1950's and 1960's is now appearing as replacement works. Vector has engaged actively in asset replacement works of its switchboards and switchgear over the past six years and this investment activity has helped in easing the financial impact in the coming years to smooth out this bow wave of asset replacement. In Figure 6-18 below it can be seen that in year five of the next ten year programme of works investment in switchboard replacement will begin to trend downward indicating the trailing edge of a 20 – 25 year "Bow Wave."

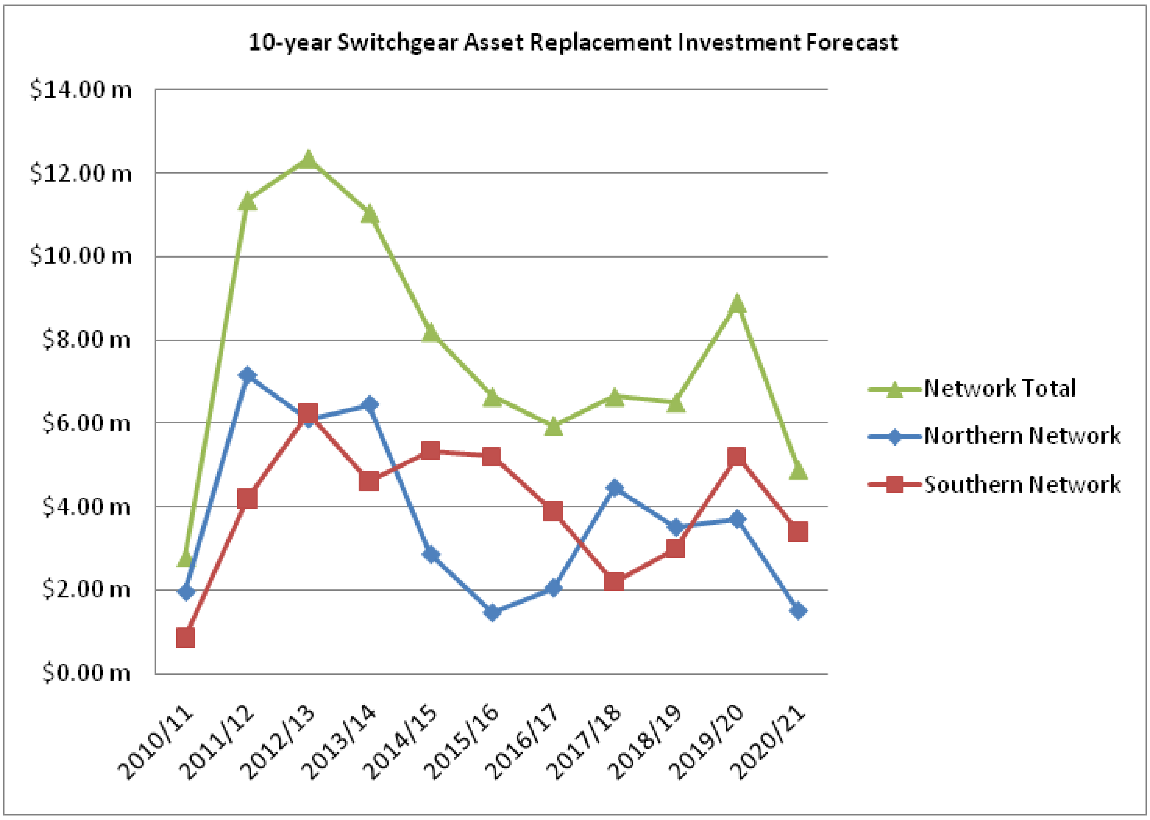


Figure 6-18 : 10-year Switchgear replacement annualised cost estimate

6.3.4 Zone Substation Buildings

Vector's primary substations are a result of two distinct design philosophies. Due to the more predominantly urban environment, substations located in the Southern region were built with the philosophy of containing as much of the primary apparatus as possible in enclosed buildings. The Northern region, initially developed largely in a rural environment, applied a more traditional approach, using outdoor switchyards for the sub-transmission apparatus with indoor control rooms and 11kV distribution switchboards.

Due to the differing design philosophies, the Northern region substations generally occupy twice the land area compared to a similarly configured urban substation. This in turn requires more maintenance (activities such as weed control, security fences, tree trimming and lawn mowing are more intensive).

For new construction, the trade-off between land and building and equipment needs to be considered, as well as the visual impact on surrounding land owners, and the security of supply. It is more costly to construct enclosed substation buildings although these costs need to be evaluated against reduced land requirements, reduced maintenance of the primary plant equipment and enhanced security of supply.

Vector's current network development philosophy for new substations is to enclose all station apparatus regardless of network region.

Newly constructed substations in the past few years have been of pre-cast concrete tilt up construction. These stations have been designed for ease of construction, low maintenance, safety of persons and adjoining properties, and compliance with the latest building and seismic requirements. These buildings are also designed to be in keeping with the local environment where they are located and are intended to be architecturally pleasing. For rural sites the design is less architecturally enhanced due to the reduced need to blend in with the urban environment facilitating some construction cost reductions.

Vector has also begun a process of evaluating the long-term requirements of the more rural aged substations with a view to convert the outdoor yards where it is economically viable to do so.

Vector redeveloped the Swanson zone substation in 2010 with a replacement of the outdoor 33kV infrastructure with a containerised indoor switchboard. The outdoor yard had reached the end of it design life, was exhibiting signs of significant deterioration of the bus works, insulators and outdoor breakers and was becoming a significant safety and supply risk. The container solution, albeit industrial in design, is in keeping with the existing station while at the same time improving the visual impact of the former outdoor apparatus. This project has also improved the security of supply for the area served by this station as well as significantly reducing the risk of injury to personnel and the public at this facility.

The remainder of Vector substations range from tin-clad wood frame buildings, to block or brick construction, wood frame as well as poured in situ reinforced concrete construction and other variants in various condition relating primarily to the age, materials and construction methodology.

Figure 6-19 : Swanson before redevelopment

Figure 6-20 : Swanson after redevelopment

Table 6-11 below shows the current number and book value of zone substations land and buildings on the Vector networks, including switching stations and a Vector owned GXP (Vector has one GXP located at Litchfield where supply is directly taken from Transpower at 110kV).

Network	Population	Book Value
Southern	56	$75 m
Northern	51	$32 m
TOTAL	107	$107 m

Table 6-11 : Primary Substation land and buildings – Population and Book Value

The substation buildings range from new to 63 years old on the Southern region and from new to 54 years old on the Northern region. In all there are 107 in service zone substations and switching stations, with an additional four zone substations currently under construction.

Figure 6-21 and Figure 6-22 show the age profile of zone substation buildings in the Southern and Northern regions.

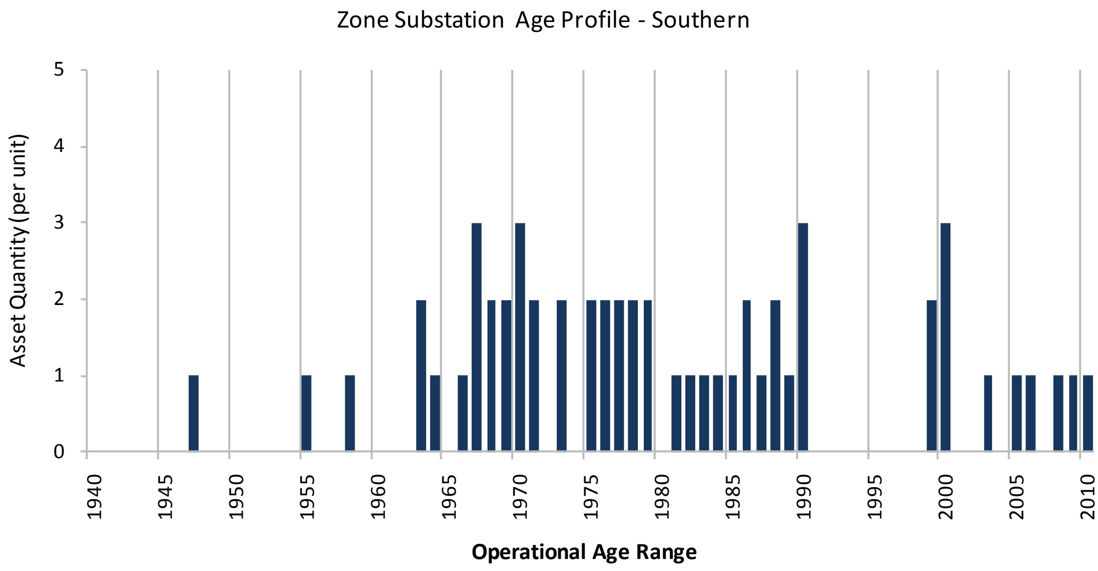


Figure 6-21 : Zone Substation Buildings Age Profile - Southern

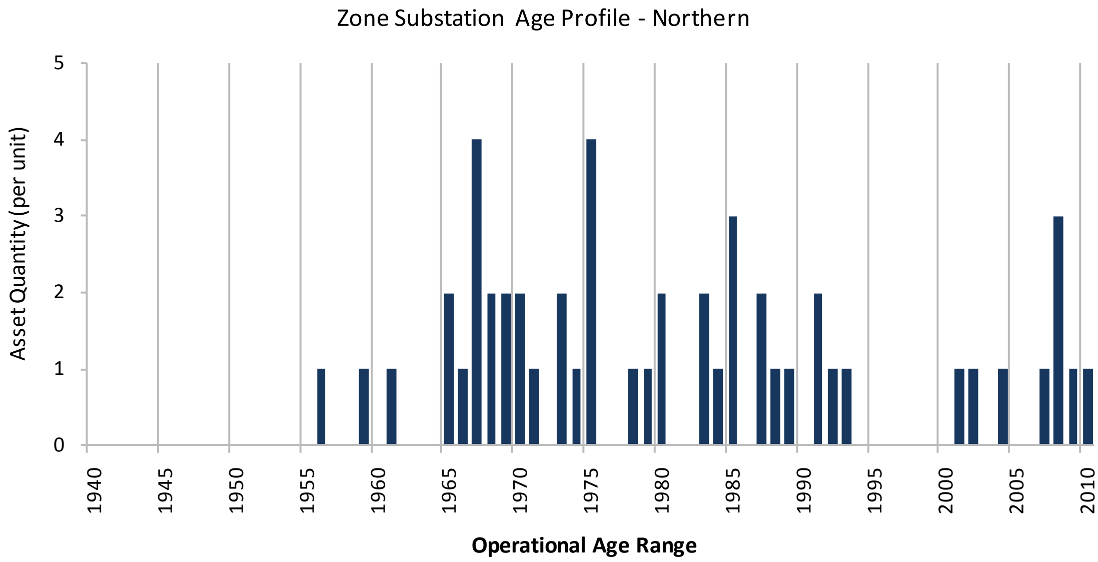


Figure 6-22 : Zone Substation Buildings Age Profile - Northern

The substation buildings vary in condition from very good to poor. The poorest, while structurally sound, are in need of upgrades due to rotting doors, rotting window frames and rusting roofs. Ongoing refurbishments of these buildings will be required.

6.3.4.1 Maintenance Programme

The substation building maintenance regime covers substation building structures, fire detection and protection, ventilation systems, environmental control fixtures, grounds, driveways, external lighting, fences, security systems, emergency lighting, and power supplies.

Maintenance intervals are specified in Vector standard ENS-0188 and maintenance activities defined in ENS-0189.

A summary of the standards is given below:

- Routine and preventive maintenance:
    - Three weekly – grounds inspection. Ensure perimeter security fencing and gates are free from damage, all locks and chains are sound, and site signage is adequate. Structural integrity and cleanliness of external walls, doors and windows, all drains and plumbing;
    - Three weekly - vegetation service. Site vegetation has adequate building clearance and security clearance, tree pruning where necessary, edges and lawns are mown and trimmed were required, any rubbish on site or vegetation trimmings are removed, any unintended plants, weeds or mould removed from driveways, equipment yards and buildings;
    - Monthly – building compliance assessment;
    - Two monthly – electrical assets visual inspection;
    - Two monthly – buildings services visual inspection and condition assessment. Ensure telephone and radio are operational, spill kits and first-aid kits are fully stocked, extinguishers compliant, rubbish is removed, structural integrity and cleanliness of internal walls, doors and windows, all

drains and plumbing, and sump pumps and alarms are functioning as required. Test operation of substation lighting and emergency lighting, smoke detectors, intrusion alarms, electric fences and fire alarms. Test operation of radiant heaters, heat pumps and air conditioning systems where fitted, assess filter condition. Ensure all trench covers are secure, and trenches and cable ducts are sealed from water ingress. Restock any consumables;

    - Annual – alarm testing and compliance, ensure correct operation of all fire alarms, intrusion alarms and crisis alarms as required, clean and test all smoke heads; and
    - Annual – building warrant of fitness certification.

- Refurbish and renewal maintenance:
    - All defects that are not considered an imminent risk of asset failure, or a compromise in site security require repair or replacement before the next inspection is due.
- Fault and emergency maintenance:
    - All defects that are considered to pose an imminent risk of asset failure, or a compromise in site security require immediate repair or replacement.

6.3.4.2 Refurbishment Programme

A survey of all stations is intended to be carried out in the 2011/12 financial year. It is anticipated this will result in a refurbishment programme commencing in the 2012/13 financial year. The survey work will also include seismic evaluations of all zone substations. The evaluation process is indicated in the schematic in Figure 6-23.

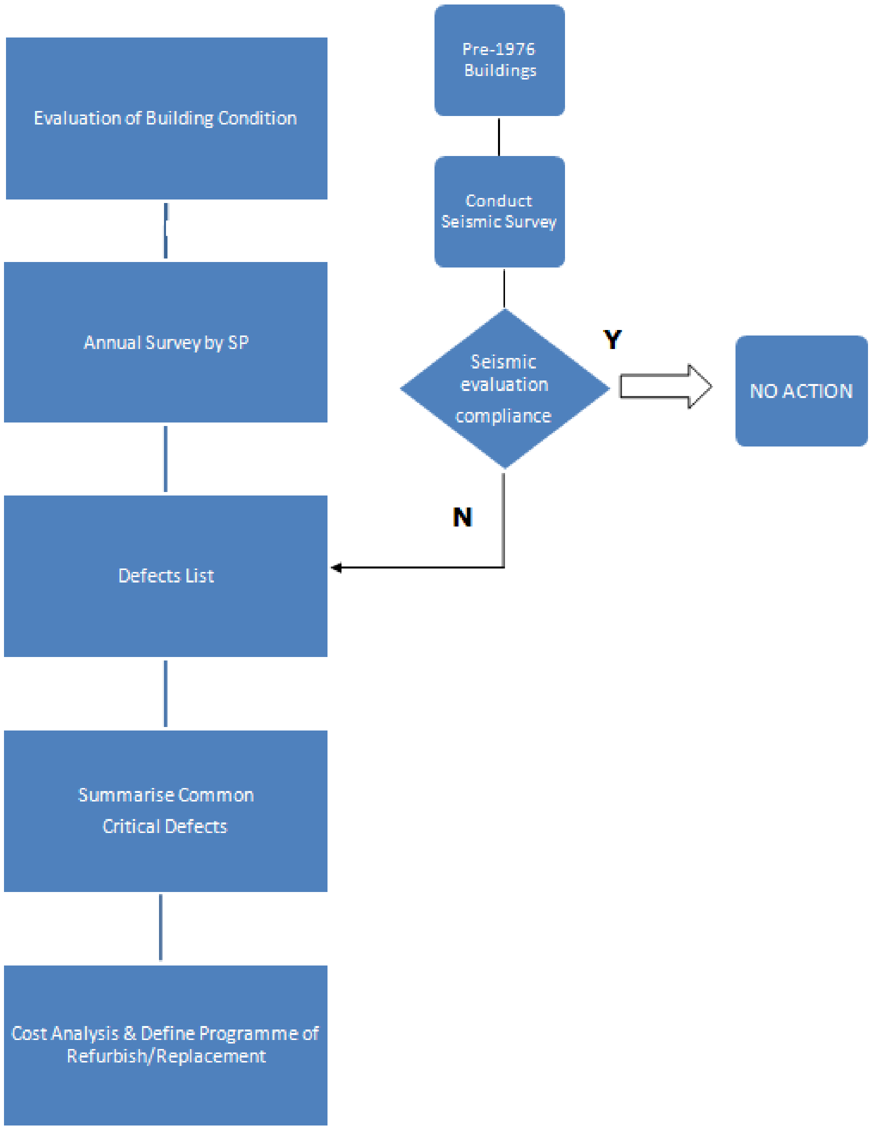


Figure 6-23 : Zone substation renewal process

6.3.4.3 Seismic Upgrades

The local authority has been empowered to enforce the seismic compliance rules of the Building Act 2004. Section 122 of the Building Act requires assessments be made of certain structures (single story houses etc are exempt) to verify their performance under earthquake conditions. Section 131 of the Building Act 2004 requires that local authorities develop a policy relating to dangerous and insanitary buildings within their areas of jurisdiction.

The Building Act defines a "Seismically Prone Building" as one that does not meet the requirements of 1/3 of the current Earthquake provisions in NZS1170. The New Zealand Society of Earthquake Engineering (NZSEE) has published a document "Assessment and Improvement of the Structural Performance of Buildings in Earthquakes dated June 2006." This document provides a means of determining the likely level of seismic compliance that a building may have. It takes into account many factors such as the importance of the building and its likely impacts of failure of the structure on the public.

The importance of seismic assessment and being prepared for this risk has been very graphically demonstrated following the recent major earthquakes in Christchurch. Vector is assimilating the findings and learning from these events and will take this into account in its review of the substation buildings.

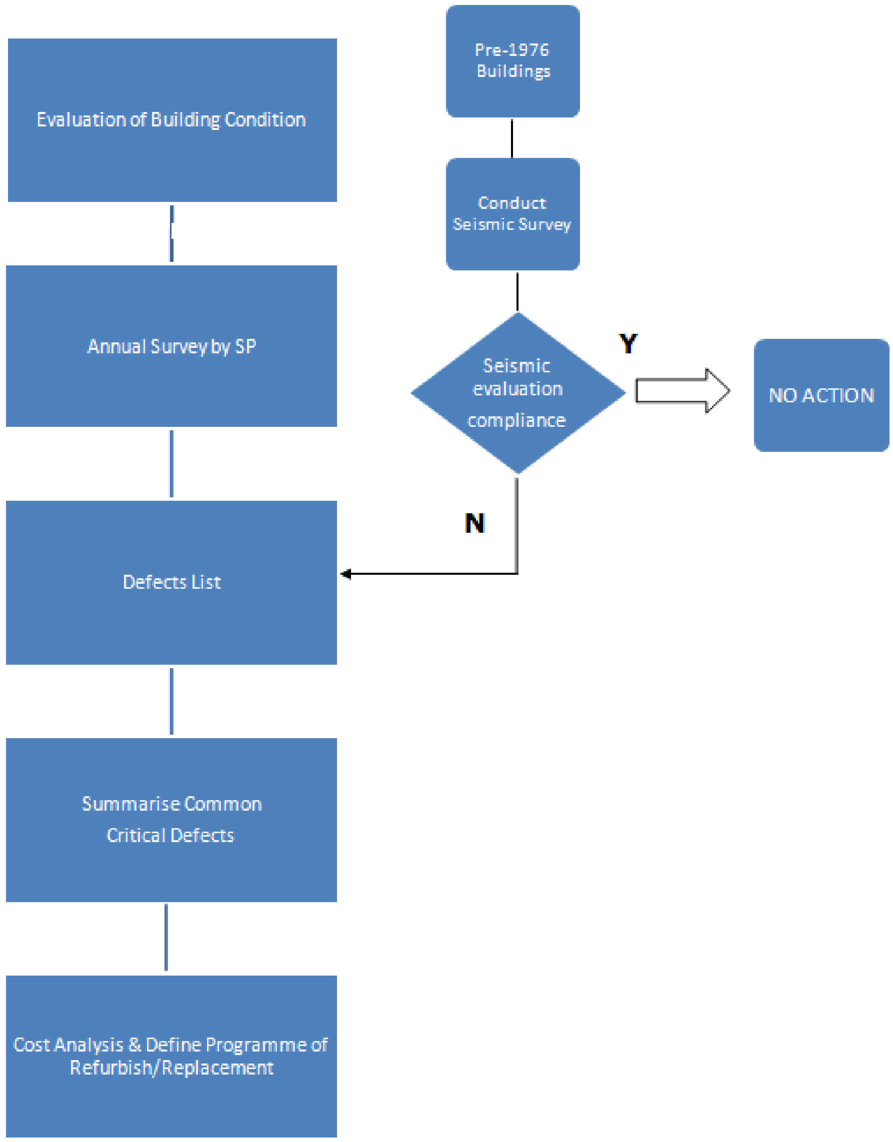


Figure 6-24 : Zone substation renewal process

A building is deemed to be “Earthquake Prone” if it fails to meet the requirements of 1/3 of the resistance required in the NZSEE document mentioned above. This is a legal requirement. There are assessment methods that can be used to rank buildings into likely (to exceed legal requirements) or unlikely (to exceed legal requirements). For example:

- Most buildings designed after 1976 will easily meet this legal requirement as they would have been designed to NZS4203 which included significant seismic design criteria;
- Similarly most light weight timber framed buildings, if they are single storey and lightly clad, will easily meet the legal requirements;
- Conversely unreinforced masonry buildings and lightly reinforced mass concrete buildings will be unlikely to meet the above legal requirements;
- The age of the building is important as it indicates not only the length of asset life left but also the likely design code they would have been designed to. Any buildings built earlier than the 1960s are unlikely to have an adequate seismic performance as only nominal attention was paid to earthquake design at that time.

It is reasonable and a simple task to rank buildings into likely or unlikely categories. The age and importance of the substation can be used to help categorise the buildings also.

The Building Act requires that all public utility buildings be seismically evaluated. Vector has engaged an experienced seismic and structural engineer to evaluate all pre 1976 constructed buildings. After the assessments have been made a more defined programme of works can be made. It is expected all pre-1976 buildings will have been assessed in the current financial year with a programme of remedial and major works identified in subsequent financial years.

At the time of writing, the stations listed in

Table 6-12 below have been assessed with an estimate of seismic upgrade works made. Compliance with the provisions of the 2004 Building Act is ten years from when council have made their own determinations. Vector is identifying affected stations now in order that annualised budgets can be established. The following table depicts the stations that are identified thus far. The review process is not completed as yet therefore it is assumed that more stations may be subject to reinforcement or renewal.

Vector Substations	***Final Report***	***Summary of works Required***	***Estimated Cost for Seismic compliance***
Avondale	Complete	Replace or strengthen the cavity brick panels to the Switch Room Building. Add roof bracing to the underside of the purlins. Replace or strengthen the brick panels to the Transformer Bay Building. Strengthen the concrete pilasters to the walls of old part of the Transformer Bays. A detailed analysis of the wind loads and seismic loads on this structure should be carried out.	$740,000
Balmain	In Progress		
Balmoral	In Progress		
Belmont	In Progress		
Birkdale	In Progress		
Brickworks	Complete	It is recommended that this building be demolished and a new switch room be rebuilt meeting the future expected needs of Vector. It may be possible to reinforce and concrete (gunite) the exterior concrete masonry walls of the switch room to provide some level of service and protection against minor earthquakes. However, the problem with the fire condition will not be resolved by doing this work.	$1,200,000
Browns Bay	In Progress		

Vector Substations	Final Report	Summary of works Required	Estimated Cost for Seismic compliance
Carbine		A detailed analysis of the seismic loads on this structure has been carried out to determine what level of seismic acceleration this structure can provide. This analysis predicts this structure can easily resist the 1/3 NZS 1170 Seismic provision. This building meets the required standard for seismic resistance for old buildings of the Building Act.	$0
Greenmount	In Progress		
Hans	In Progress		
Helensville	Complete	No remedial work is required to make this building comply with the Seismic Provisions of the Building Act	$0
Henderson Valley	In Progress		
Hobson	In Progress		
Kingsland (Est. 1946)	Complete	The insitu concrete strength of the walls and sub floor structure should be determined by taking core samples at strategic positions.. The results of the above core samples should be used in a detailed seismic assessment to determine the likely level of performance of this structure	$15,000
Kingsland (Est. 1962)	Complete	Vector should consider replacing or strengthening the cavity brick wall cladding to the Switch House Building. There are several alternatives which can be used in this case. Alternative 1 is to remove the exterior brick layer, drill and place masonry anchors and into the inner brick layer add mesh reinforcing and gunite (sprayed concrete) the exterior surface of the bricks. This will form a structural panel which will resist seismic loads. There may be moisture problems with this method. This work can be done without affecting the operation of the electrical function of this building. Alternative 2 is to remove both layers of brick and the capping sill and replace these with light weight timber framed construction with fire resistant cladding and lining. This alternative would require the shut-down of the electrical function of this building.	$180,000
Laingholm	In Progress		
Liverpool -1 (Est. 1964)	Complete	A detailed analysis of the seismic loads on this structure should be carried out to determine the likely lateral movement of this structure with respect to the allowable movement of the electrical plant within the structure. A geotechnical assessment should be made on the stability of the large retaining walls along the eastern and southern boundaries. Unreinforced cavity brick and concrete block walls should be either strengthened or replaced with light weight fire rated walls. The unreinforced concrete block panels in the western boundary wall should be removed and the concrete framing structure around the panels demolished. The ceiling to the roof of the building should be checked for the suitability of the 12mm thick asbestos fire resistant coating. If it is felt that this asbestos is a health risk it should be removed and a new fire rated ceiling system installed. This may result in strengthening of the portal frames.	$1,100,000
Manurewa	In Progress		

Vector Substations	***Final Report***	***Summary of works Required***	***Estimated Cost for Seismic compliance***
Maretai	Complete	A detailed inspection of the structure of these buildings should be undertaken by a chartered engineer to determine what, if any, remedial works should be undertaken. Strengthening of the roof trusses is advised in the Existing 11kV Switch Room to resist earthquake and uplift forces from wind. An attempt has been made to quantify the costs for these remedial works, however since the condition of the building is unknown to the author, these costs cannot be accurately determined. It is recommended that a condition assessment be made on this building and detailed estimate of costs be obtained from a qualified builder. Vector Ltd may wish to further assess the necessity of doing any or all of the above depending upon its Asset Planning initiatives for this building. (i.e. Vector Ltd may choose to reconstruct the sub-station to suit its future plans).	$50,000
McNab	In Progress		
Milford	In Progress		$1,200,000
New Lynn		It is recommended this building be demolished and a new switch room be rebuilt meeting the future expected needs of Vector. It may be possible to reinforce and concrete (gunite) the exterior concrete masonry walls of the switch room to provide some level of service and protection against minor earth quakes. However, the problem with the fire condition will not be resolved by doing this work	New Building with provision for 2 XFMR bays as per template design $ 1.2 M (no equipment).
Onehunga	In Progress		
Orakei	In Progress		
Otara	In Progress		
Pakuranga	Complete	The double skin brick panels in the Switch Room are required to be either: a) removed and replaced with light weight timber framed panels that are adequately fire rated, or b) strengthened by adding a reinforced concrete “gunite” inner lining to the panels to provide the requisite shear strength. This is the recommended solution as it causes less inconvenience to the internal lay out and running of the switch gear). The unreinforced concrete block walls between the transformers and the cooling plant should be strengthened by adding a reinforced concrete “gunite” lining to the wall to provide the requisite shear strength. An attempt has been made to quantify the costs for these remedial works. However, since the condition of the building is unknown to the author, these costs cannot be accurately determined. It is recommended that a condition assessment be made on this building and detailed estimate of costs be obtained from a qualified builder	$370,000
Parnell	Complete	No remedial work is required to make this building comply with the Seismic Provisions of the Building Act.	$0
Pt Chevalier	Complete	No remedial work is required to make this building comply with the Seismic Provisions of the Building Act.	$0
Quay St	In Progress		
Riverhead	In Progress		
Sabulite	Complete	It is recommended that this building be demolished and a new switch room be rebuilt meeting the future expected needs of Vector Ltd. It may be possible to reinforce and concrete (gunite) the exterior concrete masonry walls of the switch room to provide some level of service and protection against minor earth quakes, however the problem with the fire condition will not be resolved by doing this work	New Building with provision for 2 XFMR bays as per template design $ 1.2 M (no equipment).
Swanson	Complete	Additional bracing should be provided to each of the long walls. This can be achieved by either adding bracing panels or by providing some sort of strap bracing fixed to the internal timber framing.	$15,000

Vector Substations	Final Report	Summary of works Required	Estimated Cost for Seismic compliance
The Drive	In Progress		
Triangle Rd	Complete	A detailed inspection of the knee braces and wall braces of this structure and their connections should be undertaken by a chartered engineer to determine what, if any, remedial works should be undertaken. This assessment should not only focus on the structural aspects of this building but also the security and fire resistance systems. A detailed assessment of the fire resistance of the internal linings of this structure should be undertaken. Fire resistance and protection systems should be added to the roof trusses, knee braces and RSC columns. The windows along the side walls should be removed and timber infill framing and appropriate cladding should be installed. An attempt has been made to quantify the costs for these remedial works. However, since the condition of the building is unknown to the author, these costs cannot be accurately determined. It is recommended that a condition assessment be made on this building and detailed estimate of costs be obtained from a qualified builder	$260,000
Victoria	In Progress		
Westfield	Complete	Thorburn Consultants have assessed the design and condition of the Westfield Substation at 39% NBS. This result gives the building a “C” grade (moderate risk) from the initial evaluation criteria. Under the evaluation criteria set out by the NZSEE, Thorburn’s assessment has assumed the building to be considered as a category 3 public utilities building rather than a category 4 post Disaster building	
		Total Investment	$5,130,000

Table 6-12 : Zone substations seismic compliance survey

Vector continues to engage with local authorities on the building and seismic compliance requirements for existing zone substations. An annual budget of $1 million dollars for each network (Northern and Southern) has been allotted for the duration of the ten year programme to accommodate building reinforcement works. Some buildings cannot be economically seismically reinforced (eg. Brickworks, Sabulite Rd, New Lynn) and will have to rebuilt. These stations are identified in the current 10 years program of works.

Vector also has an ongoing programme of oil containment for power transformers to ensure compliance with environmental regulations. This programme has been under way since 2005. By 2012 all substations are expected to have effective oil containment measures in place.

6.3.5 Zone substation DC supply and auxiliaries

Substation direct current (DC) auxiliary power systems provide supply to the substations’ protection, automation, communication, control and metering systems, including power supply to the primary equipment motor driven mechanisms. Vector’s standard DC auxiliary systems consist of a dual string of batteries, a battery charger, a number of dc/dc converters and a battery monitoring system. The major substations are equipped with a redundant dc auxiliary system.

Vector faces a number of issues in relation to its DC supplies and auxiliaries at substations:

- In general the Southern network asset condition is considered to be average, while on the Northern network it is fair to poor;
- There are many substations with a mix of 110V/30V/24V supplies. This complicates effective maintenance;
- Many DC charger supplies are reaching the end of their life;
- Some output capacitors are drying out, causing excessive output voltage ripple. This reduces asset life;
- Many older chargers are not temperature compensated; and
- Many older chargers have insufficient output capacity to supply the substation without battery banks, and take too long to bring banks back up to full capacity (again reducing asset life).

An age profile is provided in Figure 6-25 below.

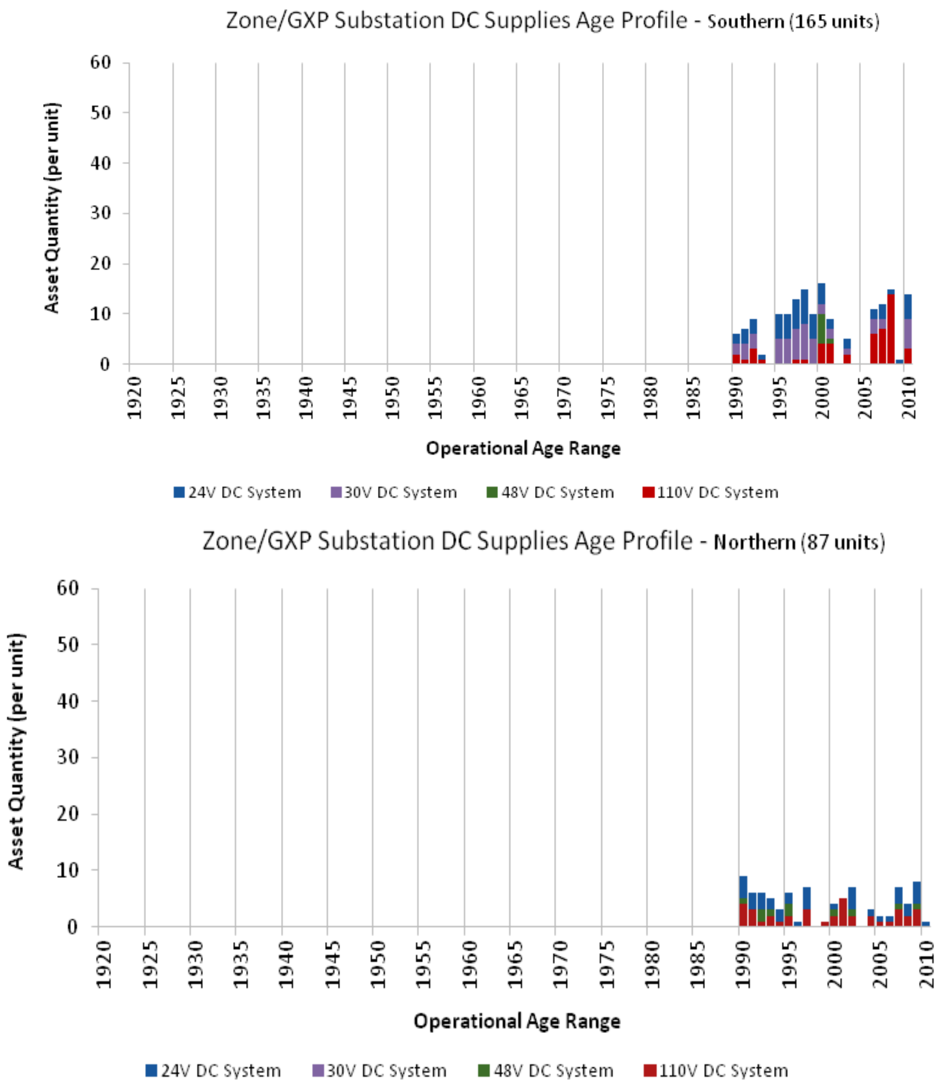


Figure 6-25 : Zone substation DC supplies – age profile

Maintenance for the valve regulated lead acid (VRLA) batteries is based on the recommendations of IEEE–1188 (IEEE Recommended Practice for Maintenance, Testing and Replacement of VRLA Batteries for Stationary Applications). Battery monitoring is an essential process for security of supply, ensuring battery systems continue to have the capacity to operate equipment during a supply outage and to enable restoration of supply once any contingency has been rectified.

Vector is implementing online battery monitoring in its substations. The intention is to in future progressively reduce the requirement for onsite maintenance and inspections.

The following display, in Figure 6-26, is an example of remote on-line monitoring capabilities of a recently installed DC auxiliary system in a distribution substation.

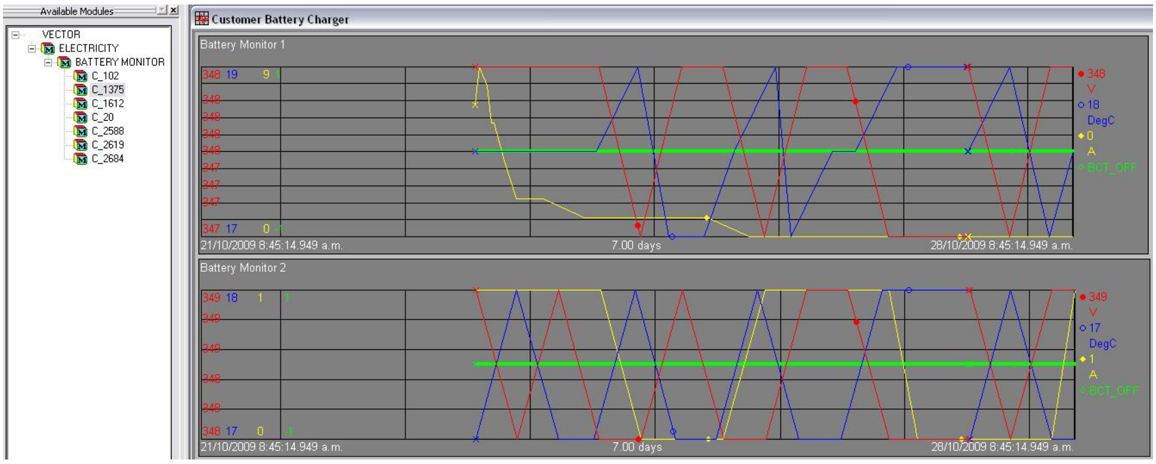


Figure 6-26 : Station batteries remote on-line monitoring

To address the issues listed above that Vector faces with its DC and auxiliary supplies, a systematic replacement programme has begun.

6.3.6 Power System Protection

All of Vector's primary switchgear and power transformers are equipped with comprehensive electrical protection systems – applying suites of protective relays. The age of installed relays is generally known and, in the absence of accurate performance data, is currently the most reliable indicator to serve as a basis for replacement. As per CIGRE and generally accepted industry practice, the useful life-span for protection relays is generally estimated to be in the following ranges:

- Numerical: 15-20 years;
- Static: 20-25 years; or
- Electromechanical: 32 years.

Vector's protection relay asset consists of 2,644 main protection relays. The age and technology distribution is given in Figure 6-27 and Figure 6-28.

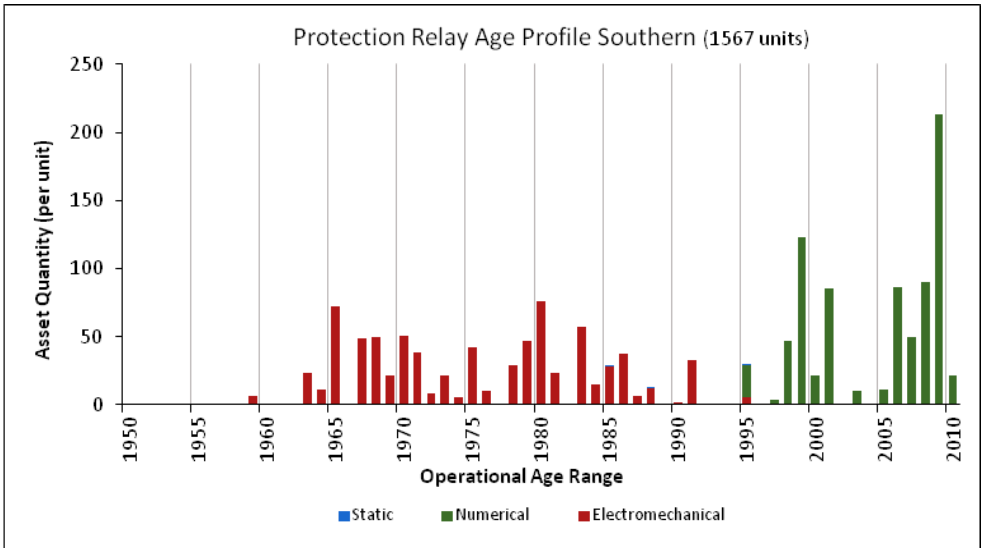


Figure 6-27 : Protection relay age profile – Southern

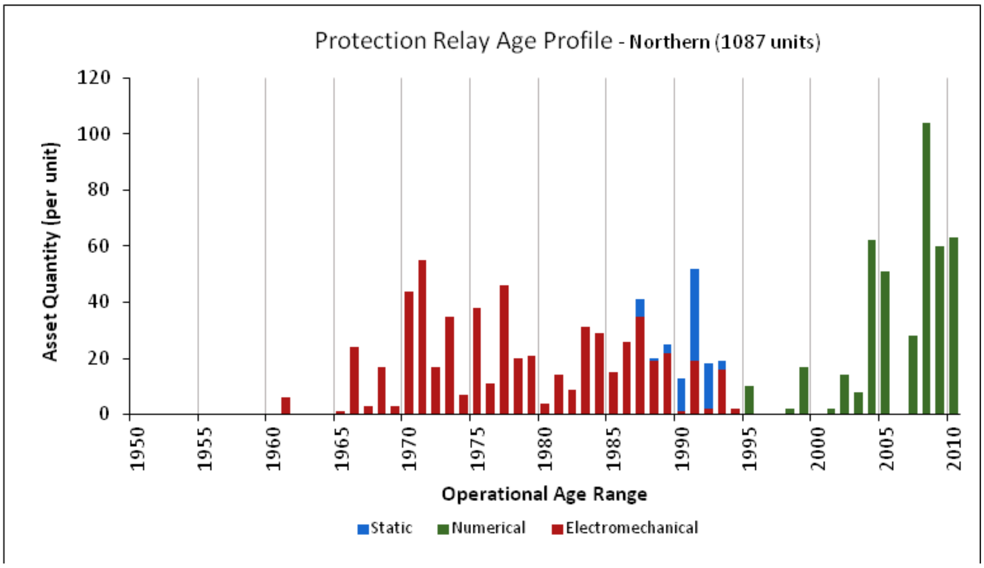


Figure 6-28 : Protection relay age profile – Northern

Vector's financial system (SAP) does not at present explicitly record the value of protection relays. This is included with the value of the switchgear it protects. Based on the cost of recently installed projects, the protection asset book value is estimated to be around $50 million.

Vector is not aware of any systemic problem with its current population of protection relays and the assets are generally in good condition.

6.3.6.1 Maintenance Programme

All protection maintenance is time-based at present. Maintenance frequencies vary depending on the generation of technology. For protection installed at the grid interface, the maintenance frequency is stipulated by the Electricity Governance Rules.

Maintenance of numerical relays (self-monitoring) is on an eight-yearly basis. Non self-monitoring relays require four-yearly maintenance. For analogue relays the period is six years, or two years at the grid interface. A summary of Vector's maintenance requirements is given in Table 6-13. If the next (eight-yearly) testing occurs after the relay has been in service for ten years the battery will be replaced.

	Numerical Self Monitoring	Digital Non-Self Monitoring	Analogue (electro-mechanical or non-numerical electronic)	Measuring / Trip Circuit	AUFLS	IED Battery Replace-ment
Grid Interface	10	4	2	4	4	8*
Other Stations	10	4	6	4/6/10**	4	8*
Trf. Mech. Protn.	**					-
Transformer IED	**					8*
Transformer Voltage Regulating Relay, OTI and WTI	**					

	Required by Electricity Governance Rules
*	Refer to note 2.
**	Align with associated protection relay (e.g. buchholz) maintenance interval.

Notes:

1. Differential protection between the grid and a connected asset to be treated as a single protection function and be tested both ends.
2. Replace 8-yearly. Battery life is estimated to be ten years.
3. Periodic testing of RTU is not required. The RTU's on-board battery shall be replaced when the battery fail alarm is activated.
4. Where CBM test results replace periodic testing, the periodic test interval start date shall be reset to the date of acceptance of CBM results.
5. Calibration and operation of measurement transducers shall be tested when protection tests are carried out. Correct reflection of measured values within specified limits shall be tested locally and remotely (SCADA). Cable pressure alarm transducers and temperature transducers shall be tested 2-yearly.

Table 6-13 : Protection relay maintenance frequencies

6.3.6.2 Replacement Programme

The basic aim of the protection equipment replacement strategy is to ensure the managed replacement of installed protection assets is carried out in order to maximise the overall benefit of the exercise to Vector and its customers. In order to achieve this, the replacement strategy must strike a balance between cost implications and avoiding the risk of asset failures or malfunction. The replacement strategy also needs to consider lifecycle management factors and ensure full protection Vector's switchgear and transformers is maintained at all times.

The key principle of the strategy is that any protection device which cannot be kept to an overall level of adequacy through routine maintenance should be replaced, given protection is a network-critical function.

For this reason the replacement strategy is pre-emptive in its approach. It is also considered essential for the protection system to be systematically upgraded in order to align with modern practices, allowing substantial benefits offered by modern protection devices to be captured. Finally, the protection system must be sustainable in terms of available skills, spares and support.

The main drivers for protection replacement are:

- Protection system inadequacy (non-compliance with system requirements);
- End of technical life;
- Reduced maintenance cost (cost efficiency);
- Improving safety;
- Improving reliability;
- Standardising and simplifying maintenance practice; and
- Standardising protection installation designs.

The above drivers are balanced against the cost of replacement and practical/operational considerations, and some compromise is therefore necessary.

6.3.7 System Control and Data Acquisition - SCADA

The Vector SCADA system is made up of the following components:

- SCADA master stations

  Vector operates two SCADA master stations to monitor and control its electricity network. A Foxboro LN2068 system is used for the Northern region and Siemens Spectrum Power TG is used for the Southern region. A project is under way to complete migration of Northern region SCADA to the Power TG system and to retire the ageing LN2068 system. This is to ensure consistency across our network and to make design, commissioning and maintenance activities more efficient.

- Remote telemetry units (RTU)

  Over time a number of different RTUs have been installed in Vector's network, many of which are nearing the end of their technical life or are obsolete. Vector has been running an annual RTU replacement programme for a number of years which is currently replacing approximately ten RTUs per region per annum. RTUs are replaced with a standard interface to both master stations.

  In the Southern region there are 40 Plessey GPT RTUs and Siemens PCC systems to be replaced in the coming years.

In the Northern region 33 Foxboro C225 RTUs and three Foxboro C50 RTUs are planned for replacement.

- Communication system

  Vector is committed to an open communications architecture based on industry standards. This has resulted in the adoption and deployment of ethernet and internet protocol (IP) based communication technology.

  Vector's communications network consists of differing architectures and technologies, some of which are based on proprietary solutions. The physical network infrastructure consists of a mix of optical fibre, copper (Cu) wire telephone type pilot cables and third party radio communication systems.

  In the next five years it is planned to decommission the legacy systems (NOKIA PHD and Siemens OTN) and migrate the operations services.

6.3.8 Load Control Systems

Vector's load control system consists of audio control frequency ripple control plants, pilot wire system and cycle control plant to manage or control:

- Residential hot water cylinders and space heating (load shedding);
- Street lighting;
- Meter switch for tariff control;
- Time shift load to improve network asset utilisation;
- Time shift load to defer reinforcement of network assets; and
- GXP demand to reduce charges from Transpower.

An overview of Vector's load control systems (pilot and ripple based), with their associated age profiles, is given in Table 6-14 and Table 6-15.

It is recognised emerging technologies, notably smart meters and/or intelligent home energy control devices, are likely to supersede existing load control systems in the near to medium-term future. Vector's intention is to maintain these to an acceptable economic standard during the transitional phase.

Network Area	Site	Manufacturer	Type	Frequency (Hz)	Power Rating (kVA)	Age (Years)	Protocol	Injection Bus (kV)	Duty Cycle (Telegram/h)
Takapuna									
(Albany GXP)	Torbay	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Waiake	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	James St	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Wairau Valley	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Bush Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Helensville	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Manly	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Belmont	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Ngataringa Bay	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Hauraki	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Highbury	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Balmain	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Birkdale	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Northcote	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Hillcrest	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Browns Bay	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Sunset Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	East Coast Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
Network Area	**Site**	**Manufacturer**	**Type**	**Frequency (Hz)**	**Power Rating (kVA)**	**Age (Years)**	**Protocol**	**Injection Bus (kV)**	**Duty Cycle (Telegram/h)**
	Forest Hill	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Milford	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Orewa	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
(Henderson GXP)	Woodford Ave	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Te Atatu	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Triangle Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Hobsonville	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Swanson	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Riverhead	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Simpson Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
(Hepburn GXP)	Henderson Valley	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	McLeod Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Laingholm	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Brickworks	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Atkinson Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Sabulite Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	New Lynn	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Waikaukau Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-

Table 6-14 : Asset age profile - Northern region – pilot wire system

Network	Type	Year of Manufacturer	Population
Northern	Rotary	1961	2
Northern	Rotary	1965	5
Northern	Rotary	1967	1
Northern	Rotary	1976	1
Northern	Cyclo	1983	2
Southern	Static	1990	3
Southern	Static	1992	1
Southern	Static	1993	2
Southern	Static	1994	2
Southern	Static	1995	5
Southern	Static	1996	1
Southern	Static	1997	1
Southern	Static	1999	1
Southern	Static	2002	1
Southern	Static	2005	1
Southern	Static	2006	1
Total (units)			**30**

Table 6-15 : Ripple load control population

6.3.9 Sub-transmission and Distribution Overhead network

The overhead line system consists of 26 km of 110 kV line, 363 km of 33 kV line, 3 km of 22 kV (linked to the adjacent Counties Power network), 3,813 km of 11 kV line and 4209 km of 400 V line. Vector also has 24 km of 6.6 kV line in service on the Southern region, but this is being progressively uprated to 11 kV.

Around 115,000 poles support the overhead distribution network of which 11% are wood and the rest concrete. There are also steel towers on the Northern region primarily supporting 110 and 33 kV circuits.

New Vector poles are concrete, with the exception of a very small number where specific conditions (such as requirements for resource consent, or to access difficult locations) dictate otherwise. For these exceptions, Copper Chromium Arsenic (CCA) treated softwood poles are used. Older wood poles are either hardwood or creosote treated softwoods.

Historical asset information obtained from the Vector GIS for the Southern region, in particular age information, is deficient due to historical legacy issues.[5] Through Vector's ongoing surveys, inspection and test programmes as per ENS-0188, this data is being corrected over time.

The number of poles in each area is summarised in Table 6-16 below.

Concrete	HV	MV	LV	Total
Southern	0	22328	23066	45394
Northern	68	46854	13822	60744
Total	68	69182	36888	106138

Wooden	HV	MV	LV	Total
Southern	0	1968	3911	5879
Northern	76	1302	1546	2924
Total	76	3270	5457	8803

Steel	HV	MV	LV	Total
Southern	0	0	15	15
Northern	63	71	22	156
Total	63	71	37	171

Table 6-16 : OH Structures – Population by Material Type

[5] This includes the fact that for the ODV valuation methodology prescribed by the Commerce Commission, poles are not separately recorded.

The age profiles of the wooden and concrete poles on the Vector network is presented in Figure 6-29 and Figure 6-30.

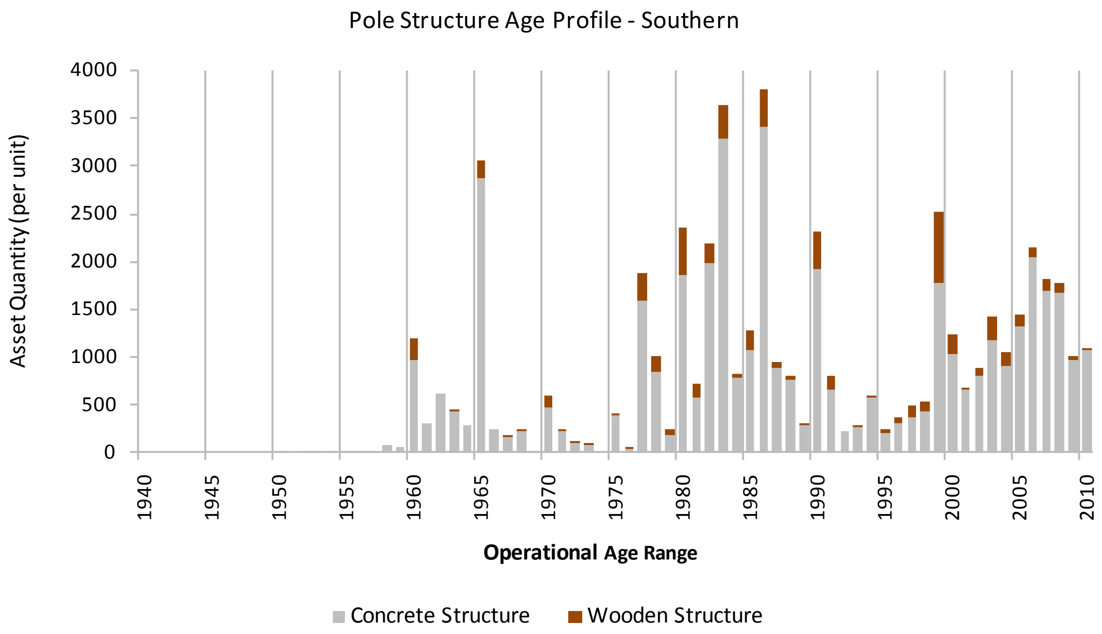


Figure 6-29 : Pole Structure Age Profile – Southern

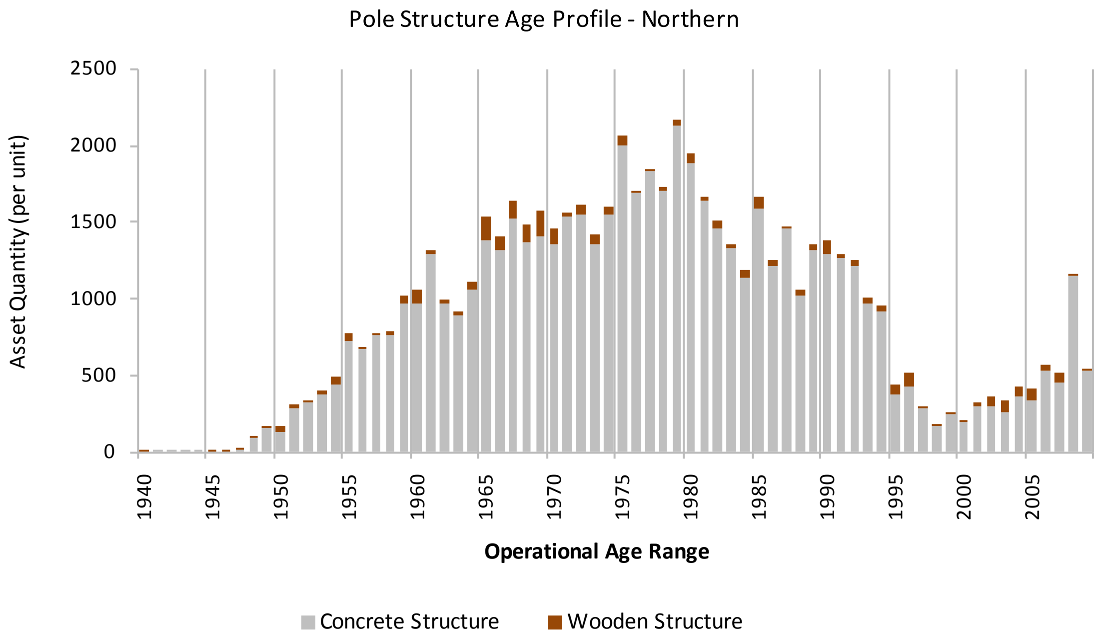


Figure 6-30 : Pole Structure Age Profile – Northern

There are 103 steel towers in the Northern region. These were originally installed by the State Hydro Electricity Department and although most are more than 80 years old, they are in good condition following extensive reconditioning works over the past few years.

Based on the Vector GIS records, the total value of the wood, steel and concrete poles on the Southern region is $320.0M and on the Northern region is $402.9M. Due to legacy/historical data issues, detailed replacement cost profiles cannot be prepared at this stage. Following Vector's current programme to update historical asset performance information this situation is expected to improve.[6]

It should be noted that the figures used above apply to 'dressed' installed poles. The value of a single pole has been assessed by sampling a number of work packs, rejecting the obvious outliers, and taking the mean of the remaining values as the value of a single pole.

It has recently been reported that some number 1 vierendeel poles have failed through corrosion of the steel reinforcing at the spacer block interface near the base of the pole. This is not easily detected though visual inspection and further investigations are underway.

6.3.9.1 Inspection and test programme

Poles and towers are visually inspected on an annual basis, as per Vector standard *ENS-0187*, and their serviceability with regard to their assessed loading is tested every give years, as per the Line Design Handbook HB C(b) and AS/NZS 4676.

Wood poles are also ultrasound tested to obtain a measure of the condition of the timber and to determine the strengths of the poles. Any pole not meeting serviceability requirements is programmed for replacement *(ENS-0057)*. There is no equivalent test programme for concrete or steel poles.

A summary of the standards is given as follows:

- Routine and preventive maintenance:
  - Annual – ground based visual inspection of each pole and tower, conductors, insulators, binders and associated steel work, conductor and staywire preforms, crossarms, crossarm straps and braces, transformer platforms, bolts, connectors, fault passage indicators, stays and anchors, surge arrestors, pole mounted transformers, pole mounted capacitors, gas and ABSs, reclosers, sectionalisers, low voltage (LV) fuses, high voltage (HV) fuses, cable risers and other steel works;
  - Five yearly – wooden pole strength versus load assessment, ground based visual inspection, ultrasonic strength assessment, calculation of remaining pole strength, including site reinstatement;
  - Ten yearly – concrete pole strength versus load assessment; and
  - Ten yearly – wooden pole strength versus load assessment.
- Refurbish and renewal maintenance:
  - Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable, remediation timeframes are based on likelihood of failure creating the unsafe situation.
- Fault and emergency maintenance:
  - Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

[6] Recognising, however, that records for some of the older assets will remain unavailable.

6.3.9.2 Maintenance and refurbishment programmes

The remaining life of a pole is difficult to predict accurately, because it is dependent upon several factors. These include the pole material and construction procedures at the time, natural environment, public access and the load that is being supported.

Good quality data is required for accurate life prediction. Such data is now being collected under the Multi Utility Service (MUSA) agreement with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected that over a three-year period sufficient high-quality data will obtained for accurate future renewal predictions.

Until the end of 2012, predicted pole replacement expenditure is based on a combination of the available asset records and an assumption the performance of poles will be largely similar to that observed over the last five years. Following an improvement in Vector's pole inspection standard (ENS-0057) implemented in 2010 a moderate reduction in future replacement needs is predicted.

Poles identified as problematic during the annual inspection or test programme may be repaired on site or replaced depending upon their condition. Poles inspected that require attention are tagged according to their as-found condition, in accordance with Vector inspection and replacement Electricity Standard ENS-0057:

- Blue Tag

  Overhead line structures found to be at risk of failing to support normal or design loads, and where engineering cannot be performed on site at the time of finding the suspect structure, shall be fitted with a blue tag. A full inspection and engineering shall be completed within ten working days of the structure being believed to be in a suspect condition.

- Red Tag

  Overhead line structures found to be at risk of failure under normal loads, or with the risk of injury to any person or damage to any property, must be marked with a red tag and repaired or replaced not later than three months after the discovery of the risk of failure.

- Yellow Tag

  Overhead line structures found to be incapable of supporting design loads must be marked with a yellow tag and repaired or replaced within 12 months of finding of the incapability.

6.3.10 Overhead conductors

Conductor types and sizes on the Vector network vary across the overhead network and are predominantly copper (Cu), all aluminium conductors (AAC) or aluminium conductor steel reinforced (ACSR) conductors. A smaller quantity of all aluminium alloy conductor (AAAC) are being utilised for new line construction.

Low voltage aerial bundle conductors (LVABC) and covered conductor thick (CCT) for 11kV lines are used in areas susceptible to tree damage.

There is a small section of high voltage aerial bundle conductor (HVABC) which was installed about 15 years ago. Although the material proved to be effective for improving reliability it was not continued, due to high installation costs.

Table 6-17 below shows the amount of overhead conductor in kilometres by operating voltage region, as well as the associated current book-value.

Population	110kV	33kV	22kV	11kV	6.6kV	LV
Southern	0 km	46 km	3 km	871 km	24 km	2037 km
Northern	26 km	317 km	0 km	2942 km	0 km	2172 km
Total	26 km	363 km	3 km	3813 km	24 km	4209 km

Book Value	110kV	33kV	22kV	11kV	6.6kV	LV
Southern	$0m	$2 m	$0 m	$32 m	$1 m	$46 m
Northern	$2m	$16 m	$0 m	$51 m	$0 m	$28 m
Total	$2m	$18 m	$0 m	$83 m	$1 m	$74 m

Table 6-17 : Conductor - Population and Book Value

Figure 6-31 and Figure 6-32 show the age profiles for all conductor voltages by region.

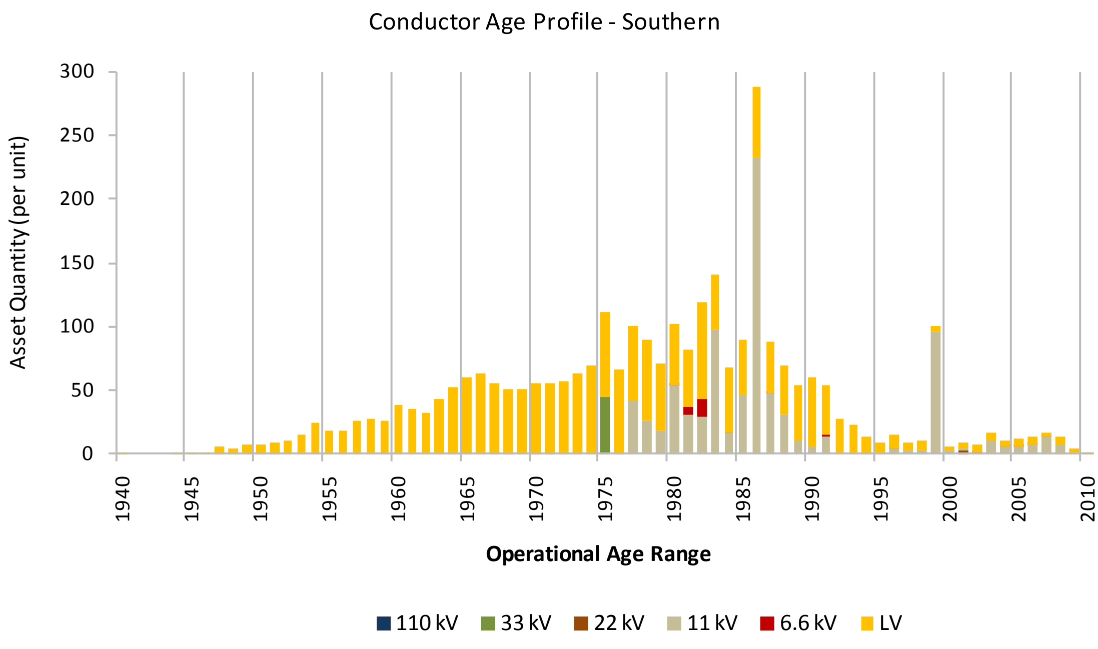


Figure 6-31 : Conductor Age Profile - Southern

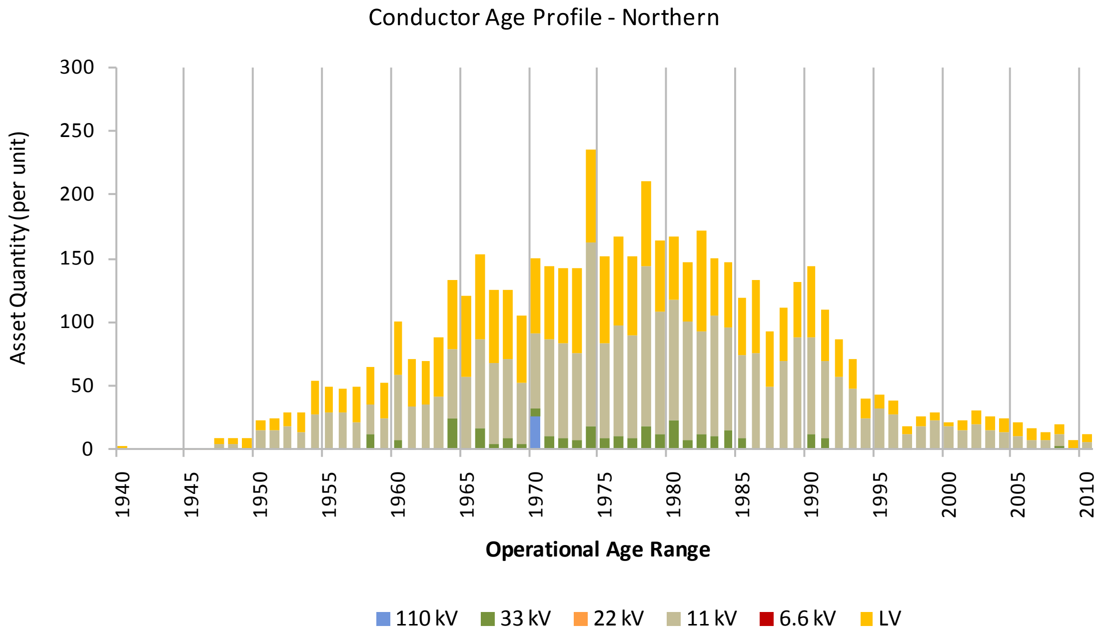


Figure 6-32 : Conductor Age Profile – Northern

The condition of the aluminium conductors and most copper conductors is good. However, there are areas reticulated with small sized copper conductors which have reached the end of their life. Vector is unwilling to even use wedge taps on these conductors because of the damage they are likely to cause to the corroded annealed copper. Vector has a replacement programme underway to address this issue. There are no other systemic issues.

6.3.10.1 Inspection and test programmes

Conductors are inspected during the annual visual line patrol of the overhead network, in accordance with Vector standard *ENS-0187*.

There is no test programme for conductors.

A summary of the standard with regard to conductors is given as follows:

- Routine and preventive maintenance:
  - o Annual – All Conductors are inspected as follows:
    - Ground clearances and conductor spacings visually assessed for adequate clearances;
    - Adequate clearance from vegetation;
    - Spans checked for balanced sags;
    - Conductors free from broken strands, corrosion and clash burn marks;
    - CCT high voltage conductors free from insulation;
    - Damage; and
    - Joints in conductors are visually secure and not showing signs of overheating.

- Refurbish and renewal maintenance:
    - o Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating the unsafe situation.
- Fault and emergency maintenance:
    - o Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.10.2 Maintenance and Refurbishment programme

The remaining life of a conductor is difficult to predict because it is dependent upon several factors. These are the conductor material, natural environment, public access, mechanical loads, electrical loads and number and magnitude of downstream electrical faults.

Good data quality is required for acceptably accurate life prediction. Such data is now being collected under the MUSA agreements with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected that over a three-year period sufficient high-quality data will be obtained for accurate future renewal predictions.

Until the end of 2012, predicted conductor replacement expenditure is based on a combination of the available asset records and an assumption the performance of poles will be largely similar to that observed over the last five years. In the Northern region, additional provision is made to include the replacement of weakened copper conductors over the next ten years.

Conductors are not refurbished but recovered conductors in good condition may be reused. Conductors are repaired or replaced when they fail, in line with industry practice.

6.3.11 Overhead switches

Overhead switches include MV air break switches (ABS), isolating links, SF_6 switches and reclosers and sectionalisers. These devices are installed to enhance network operation, allow remote switching (in some instances), reduce the impact of faults and the extent of outages and enhance reliability performance. Table 6-18 shows the population and book value of overhead switches on the Vector network.

Population	Air Break	Recloser	Gas Break	Sectionaliser
Southern	559	28	184	12
Northern	623	99	270	32
Total	1182	127	454	44
Book Value	Air Break	Recloser	Gas Break	Sectionaliser
Southern	$6 m	$2 m	$3 m	$1 m
Northern	$6 m	$3 m	$4 m	$1 m
Total	$12 m	$5 m	$7 m	$2 m

Table 6-18 : OH Switchgear - Population and Book Value

Age profiles for 11 kV and 33 kV ABS and enclosed overhead switches installed in the Northern and Southern networks suffer from insufficient data. For legacy reasons, historical records are not completely accurate. In more recent times the installation of new enclosed switches has been triggered by Vector's standard ENS-0055 which is to replace ABSs with an enclosed switch when the opportunity arises, rather than at the end of their life. This has meant the age profiles are artificially skewed and do not necessarily represent assets at the end of their useful lives. The average age of removed ABSs has been between 20 and 25 years but, as noted, this cannot be used as a reasonable proxy for the expected end of life age for an ABS, or of average age of the assets.

The age profiles in Figure 6-33 and Figure 6-34 below clearly show the transition to enclosed switches in more recent times.

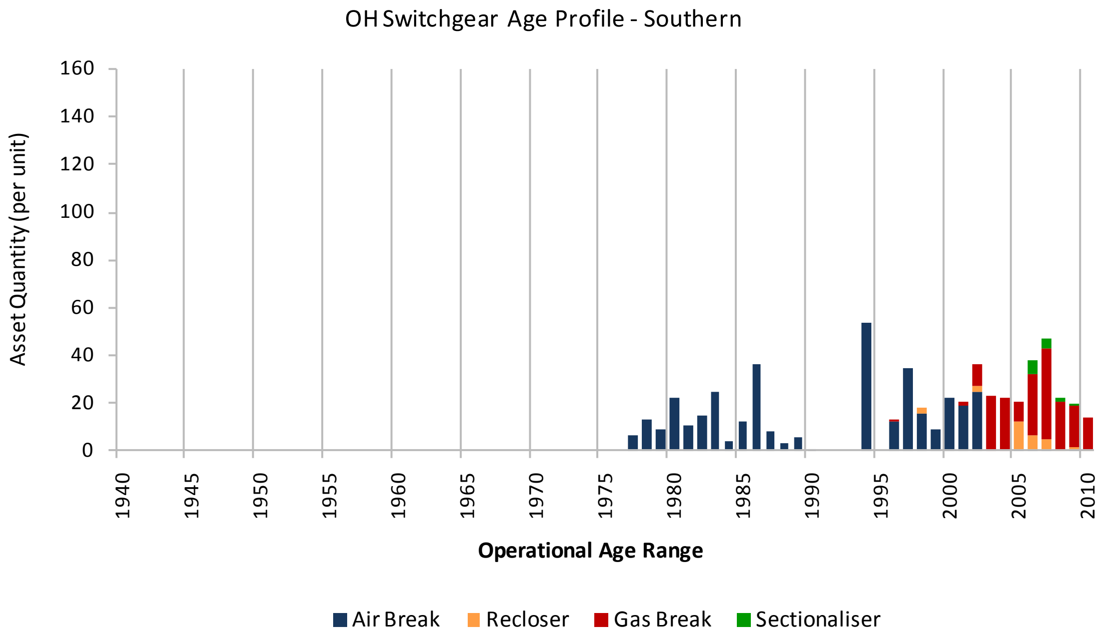


Figure 6-33 : OH Switchgear Age Profile - Southern

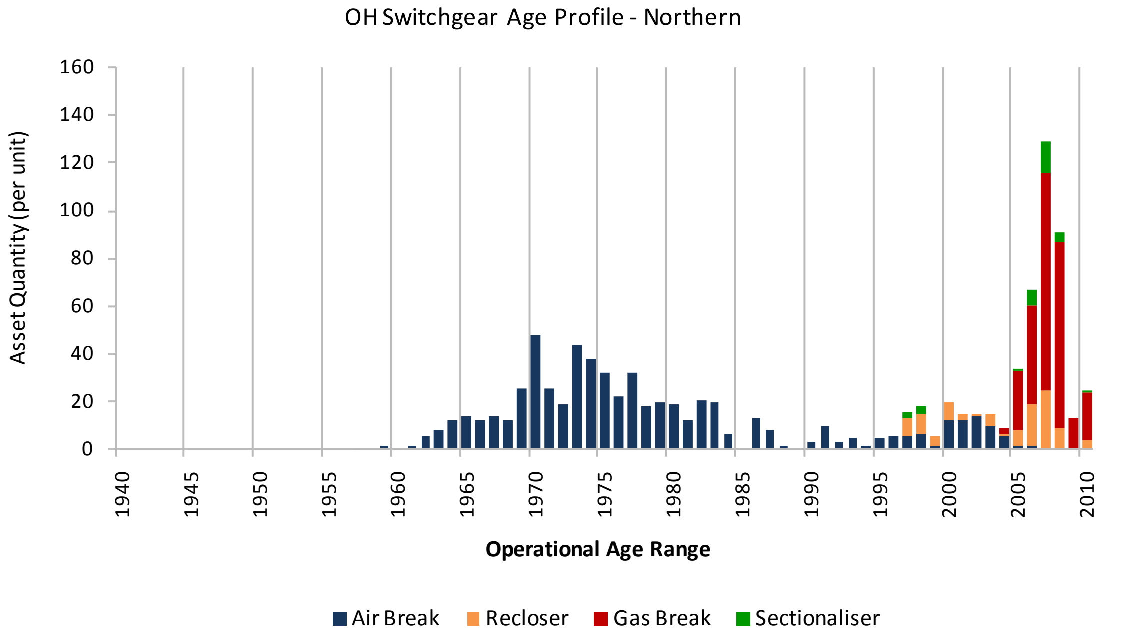


Figure 6-34 : OH Switchgear Age Profile - Northern

6.3.11.1 Condition of the asset

Most of the ABSs are more than 20 years old and are in good to fair condition. The vast majority of the SF_6 switches are less than eight years old and are in excellent condition.

The reclosers are a mixture of older oil-filled units and the newer vacuum or SF_6 insulated equipment. The older oil-filled reclosers are in good condition and the SF_6 and vacuum reclosers and sectionalisers are in excellent condition.

Vector is not experiencing any systemic problems with its overhead switches.

6.3.11.2 Inspection and test programme

Overhead switches are visually inspected during the annual line inspections, in accordance with Vector standard *ENS187*.

A summary of ENS187 with regard to overhead switches is given as follows:

- Routine and preventive maintenance:
  - Switch mechanism visually complete and aligned;
  - Support framework secure, undamaged and free from corrosion;
  - Electrical connections (including earthing) visually secure, undamaged and free from overheating;
  - Control boxes visually secure; and
  - Gas indicators where fitted showing adequate levels of gas.
- Refurbish and renewal maintenance:
  - Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable.

Remediation timeframes are based on likelihood of failure creating the unsafe situation.

- Fault and emergency maintenance:
  - o Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

ABSs are operationally tested every three years (to Vector standard ENS-0055). Enclosed switches are operationally tested every nine years. The remote control functions of switches fitted with this option are tested annually (to Vector standard ENS-0055).

A summary of ENS-0055 is given as follows:

- Routine and preventive maintenance:
  - o Three yearly - MV ABS maintenance service, functional operation testing, bucket based visual inspection, contacts cleaned, dressed and lubricated, operating mechanisms bearings and pivots lubricated, contacts adjusted for correct alignment and operation;
  - o Three yearly - thermal camera inspection;
  - o Five yearly - earth system visual inspection and remote earth testing of overall earthing system resistance, each earth bank resistance, and step and touch voltage measurement. Marginally compliant sites require step and touch voltage retesting using off-frequency injection current; and
  - o Nine yearly - MV Gas break switch bucket based visual inspection, adequate operating pressure;
- Refurbish and renewal maintenance:
  - o Non-compliant earthing locations may require additional electrodes, asphalt patching, gradient rings, equipotential grids, fenced or non-conductive enclosures or wider network solutions such as neutral earthing resistors;
  - o An identified MV ABS defect that meets the operating constraint criteria will require switch replacement if still essential, modern replacement being an enclosed SF6 switch;
  - o An identified Gas break switch defect that meets the operating constraint criteria, specifically loss of pressure, will require switch removal and return to the manufacture for repair assessment and acceptance testing;
  - o Connectors with identified thermal hotspots greater than 15 degrees above surroundings are replaced;
  - o Switch contacts with identified thermal hotspots greater than 15 degrees above surroundings will require switch replacement if still essential, modern replacement being an enclosed SF6 switch;
  - o Minor mechanical defects such as operating handles require repair; and
  - o MV wedge connectors are required on all switch installations, the associated upgrade shall be programmed within six months.
- Fault and Emergency Repair:
  - o All identified defects that pose an unsafe condition for public and property require immediate repair, replacement or isolation.

6.3.11.3 Maintenance, refurbishment and replacement programme

ABSs are maintained when tested. The enclosed ABSs do not require maintenance and are expected to have a life of about 40 years.

ABSs are replaced by an enclosed switch if they have to be removed from the pole because of a defect. They are not refurbished. Enclosed ABSs are returned to the supplier.

There is no proactive replacement programme for ABSs. However, when cluster overhead replacement and pole replacements occur, any associated ABSs are replaced with gas switches. Enclosed ABSs are also installed when system reliability issues call for a remotely operable switch.

The remaining life of an ABS is difficult to predict because it is dependent upon several factors. Typically these are the natural environment, public access, electrical loads and number and magnitude of downstream electrical faults experienced over the life of the asset.

While condition data is being collected during routine inspections, as noted above, many ABSs may have to be replaced before the end of their life. Consequently, predicted replacement expenditure is based on the assumption the current base replacement rates will increase over the next ten years, to allow for additional switches installed to improve reliability.

6.3.12 Crossarms

The crossarms on the Vector network are mostly hardwood (99%) and their condition ranges from poor to good. Vector also has a small number of steel crossarms that are in good condition.

Vector has limited information on the age profiles and book values of the crossarms on the network. This is partly as a result of the manner in which assets were categorised under ODV valuations, where pole-top structures are not separately identified.

6.3.12.1 Systemic Issues

Crossarms installed in the 1990s were durability class 3 and anecdotally are regarded as having a life of about 20 years. This is unlike the older crossarms which were more durable and were regarded as being capable of up to 40 years service. Only durability class 1 crossarms (longer life) are now installed on the network.

6.3.12.2 Inspection and Test Programme

Crossarms are inspected during the annual overhead line patrols, as specified in Vector standard ENS-0187. There is no specific test programme for crossarms.

A summary of ENS-0187 with regard to crossarms is given as follows:

- Routine and preventive maintenance:

  All crossarms shall be inspected as follows:

  - Hardwood crossarms and transformer platforms free from rot, significant cracks or splits, deformation, and signs of burning;
  - All 1.3m (4'6") low voltage arms shall be identified;
  - Steel crossarms are free from obvious rust and general deformation;
  - Concrete crossarms are free from cracking and loss of concrete;
  - Laminated pine crossarms are free from signs of de-lamination;
  - Fibre glass arms are free from signs of de-lamination or failure of the outer epoxy coating; and
  - Double arms are constructed with spacer pipes, internally nutted bolts or eyebolts, or spacer blocks.

- Refurbish and renewal maintenance:
    - o Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on the likelihood of failure creating an unsafe situation.
- Fault and emergency maintenance:
    - o Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.12.3 Maintenance, Refurbishment and Replacement Programme

The remaining life of a crossarm is difficult to predict because it is dependent upon several factors other than age. These are typically the timber species used, pre-installation seasoning, natural environment, and the load being supported.

Good data collection is required to enable sufficiently accurate life prediction to take place. Such data is now being collected under the MUSA agreements with our FSPs, enacted in November 2009. Given the inspection frequency in the preventative maintenance regime, it is expected over a three-year period sufficient high-quality data will be obtained for accurate future renewal predictions.

Until then, predicted expenditure is based on the assumption crossarms will continue to be replaced at present rates.

Defective crossarms found during the annual line patrols are replaced. Crossarms are not refurbished.

6.3.13 Overhead Network - General

Various components of the overhead network are separately discussed above. In this section some general issues Vector has regarding the overhead network, with assets that do not fit with specific categories, are noted.

All overhead structures and supported equipment are visually inspected every 12 months.

Maintenance of the overhead network is a mix of reactive (based on faults) response and condition monitoring that drive preventative maintenance programmes. With the exception of gas switches and vacuum reclosers, which are returned to the supplier for refurbishment, damaged overhead equipment is not refurbished or salvaged as it is not cost effective to do so.

Assets requiring replacement are identified during the annual overhead inspection or one of the more detailed equipment inspections. Overhead distribution components are operated to failure, but in the past, when the number of identified replacements in near proximity exceeds a certain level, cluster replacement/reconstruction programmes were initiated.[7]

6.3.13.1 Connectors

Aluminium Ampact wedge taps installed to connect Cu jumpers to aluminium conductors have been found to be corroding badly after about two years of service. These connectors were specifically selected based on the manufacturer's advice that they were suitable for a bimetal (Cu to aluminium connections) application. While the problem has so far only affected exposed coastal areas, investigations of inland areas

[7] This is to achieve cost efficiencies by avoiding the need to repeatedly return to an area to repair faults, with the associated additional set-up costs (and inconvenience to customers).

have found evidence of the same issue developing, but at a much slower rate. For all new bimetal applications, the aluminium wedge connectors are now encased in a gel box to keep moisture away from the joint A true copper to aluminium welded bimetal transition connection is being developed that will remove this requirement for a gel box.

Predicted connector replacement expenditure is based on the assumption the replacement rate will continue at present rates. This assumption will be tested as more data from routine maintenance inspections become available.

6.3.13.2 Conductor Insulator Ties

Early preformed conductor ties used a rubber cushioning packer that has a tendency to perish and cause TV interference. These are being replaced in an organic manner.

6.3.13.3 Insulators

Kidney type insulators are prone to failure and are a common source of TV interference. The use of kidney insulators has been superseded by ceramic and glass disc and polymer strain insulators.

6.3.13.4 Pole transformer king-bolts

It has been found that crossarm king-bolts have been rusting in the section of the bolt where it is encased by the crossarm. While this affects all king-bolts it is not a major safety issue for conductor crossarms as there will in most cases be secondary supports such as conductors and straps that will act to prevent the arm falling to the ground. Pole transformer king-bolts deterioration is a much more serious issue, as these are under a much heavier load and the failure of the bolt will likely lead to the transformer falling from the pole. The kingbolts, therefore, have to be replaced.

Replacement of king-bolts requires about as much effort as replacing the hanger arm. A more efficient solution has been devised, by using a retro-fit clamping support that allows the transformer arm to be supported without having to rely on the king bolt. A programme is underway to install them on all overhead transformers.

6.3.13.5 Live unused spurs

Due to concern for the safety of the general public and Vector's assets, a survey is to be undertaken to identify any existing unused live overhead HV spurs and to either dismantle or isolate them from the network. An initial estimate of $20,000 has been allowed in each area for year 20011/20012 for the survey and the removal of located spurs.

6.3.14 Distribution Cables and Accessories

Older 400V cables on the Vector network are paper-insulated and lead-sheathed while the newer 400V cables are either PVC or XLPE insulated. The 6.6 kV and the older 11 kV cables are PILC or paper insulated aluminium sheath (PIAS) construction, with the more recent 11 kV and the 22 kV cables having XLPE insulation.

Table 6-19 below shows the breakdown of distribution cables by voltage class, network and book value.

Population	22kV	11kV	6.6kV	LV	Total
Southern	27 km	1977 km	34 km	3040 km	5078 km
Northern	0 km	1224 km	0 km	1835 km	3059 km
Total	27 km	3201 km	34 km	4875 km	8137 km

Book Value	22kV	11kV	6.6kV	LV	Total
Southern	$12 m	$275 m	$2 m	$181 m	$471 m
Northern	$0 m	$140 m	$0 m	$72 m	$212 m
Total	$12 m	$415 m	$2 m	$253 m	$683 m

Note: Quantities exclude pole riser lengths of 8m per LV termination, 9m per 6.6 kV, 11 kV and 22 kV termination, and 10m per 33 kV terminations

Table 6-19 : Distribution cables - population and book value

Age profiles and book values for the distribution cables, per category and broken down per network, are given in Figure 6-35 and Figure 6-36.

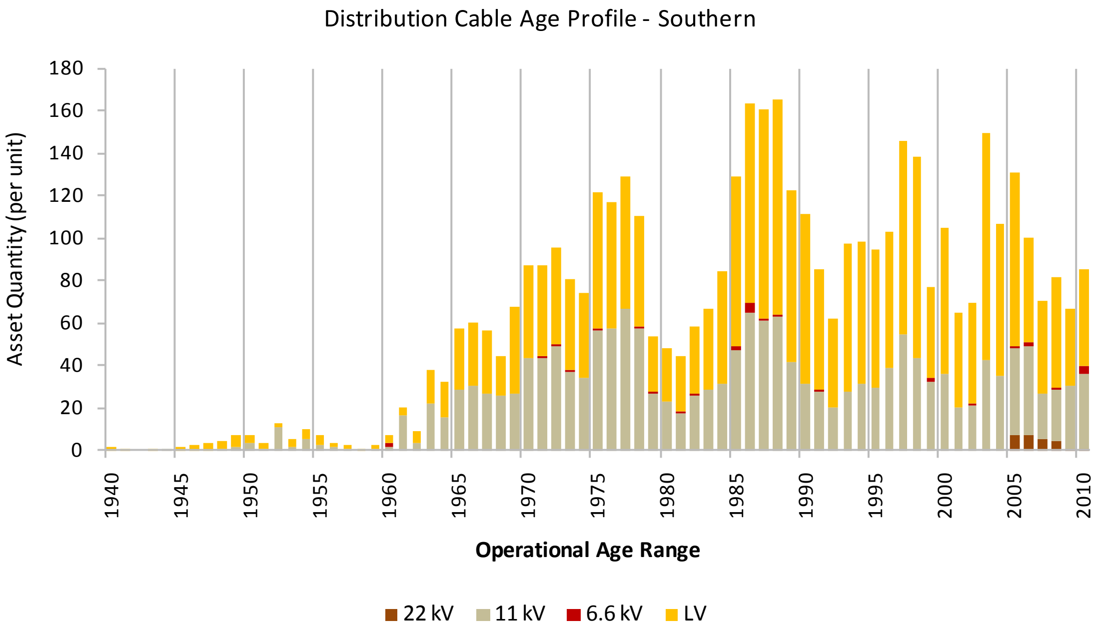


Figure 6-35 : Distribution cable age profile – Southern

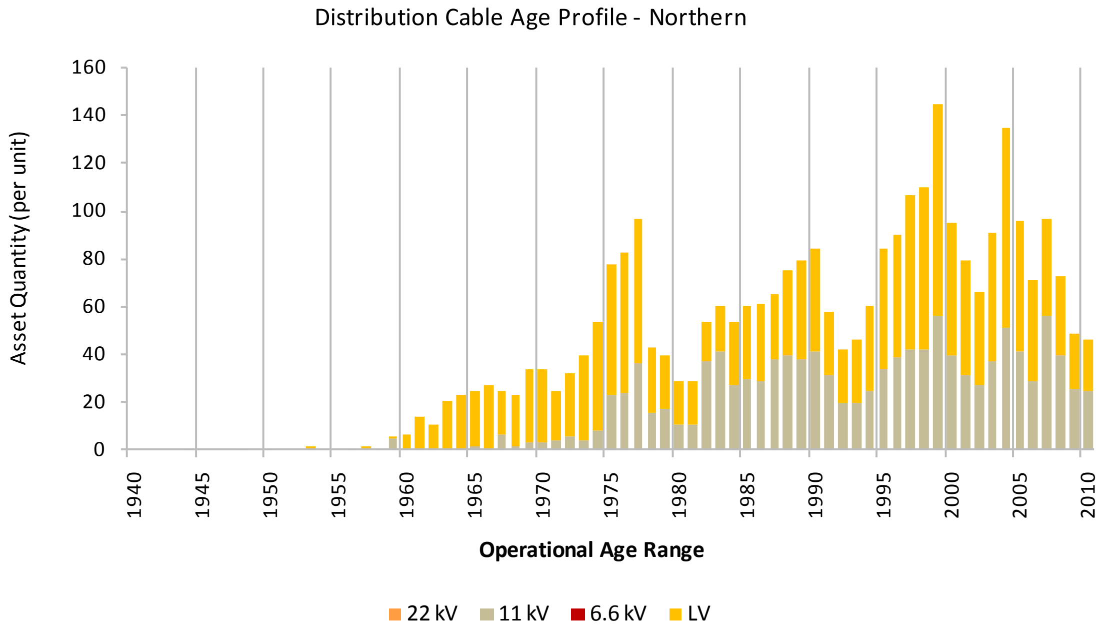


Figure 6-36 : Distribution cable age profile – Northern

6.3.14.1 Asset Condition

The 6.6 kV cables energised at 6.6 kV are operating satisfactorily. Some 6.6 kV cables which have been uprated to operate at 11 kV are showing signs of failure although based on available evidence at the time of the uprate that the 6.6 kV cables were capable of operating at 11 kV. The issues are further discussed below.

The 11 kV PILC cables are generally operating satisfactorily.

The XLPE insulated cables are in good condition, with the exception of the early natural polyethylene ('poly') cables noted below.

Systemic issues:

- **22 kV cables:** These cables are still very new, with the first having been installed in 2005. As would be expected, to date there have been no known issues. Life expectancy of these cables is 60 years but this is dependent upon factors such as the electrical load, the installation conditions and the number and magnitude of any downstream faults;
- **11 kV cables:** In the early 1970s natural polyethylene insulated 11 kV cable was installed on the Northern network. This type of cable has a high fault incidence and Vector's current practice is to repair the cable when it faults to restore supply, followed by corrective works to replace the cable in a programmed manner. Past experience has shown that once faulted subsequent faults are soon to follow, hence the decision to adopt programmed replacement;
- **6.6 kV cables:** Some cables have been upgraded to 11 kV operation, which has created issues. Some of the issues are due to failure of the joints (workmanship and insulation only designed for 6.6 kV) and others due to insufficient cable insulation. The replacement priority for these cable sections has been defined.

The issues are compounded by the fact historical records of the cables are not always correct, with some cables indicated as being rated for 11 kV where this later proves not to be the case. The full extent of the issue is still to be confirmed, as confirmation of the actual voltage rating of an operating cable requires it be opened up and the insulating papers counted to confirm suitability for operation at 11 kV (which cannot be done in normal operating conditions). Cables are treated on a case by case basis as faults occur.

Vector also has an ongoing replacement programme for the remaining 6.6 kV cables;

- **400V cables:** Faulted breech joints on to the streetlight pilot cables occur frequently. As proactive location and replacement of these joints is not practical, they will continue to be replaced as they fail; and
- **Earthing cables:** An ongoing issue with earthing cables for pole-mounted equipment is conductor theft for the scrap value of the copper. The change of our standard to use copper plated steel cables to combat this has almost eliminated the theft of new earthing cables.

6.3.14.2 Inspection and Test Programme

In practice only the terminations of underground cables are able to be inspected. Pole mounted cable terminations are inspected annually during the overhead network condition assessment, in accordance with Vector standard ENS-0187.

Outdoor terminations in zone substations are similarly inspected annually as per the Vector standard ENS-0191.

There is no regular testing of distribution power cables. Techniques such as PD mapping claim to be able to predict the health of cables. However, Vector's experience thus far is inconclusive and the technology requires further development. Long-term continuous monitoring of PD levels show promise but is currently impractical given the large number of cables involved.

The life of an underground cable is difficult to predict because it is dependent upon several factors. These are the cable construction, natural environment, public access, the electrical loads and the quantity and severity of downstream faults that the cable has experienced. In general, the best indicator of remaining life is the incidence of failures in similar installations – on which Vector is collecting data.

Underground cables are replaced when the failure rate becomes unacceptable. The benchmark level of unacceptability is more than one fault per annum. At present Vector is targeting cables exhibiting the most frequent faults and exceeding this level.

There are sections of cable that have been identified as exhibiting a high number of faults (generally ten or more faults over the past ten years). The future replacement programme for these 11 kV cables has been defined in the ten year programme of works. Vector anticipates replacing three cable sections per year for the next ten years as end-of-life failures become apparent.

Northern poly cable replacements have been historically included in the replacement programmes and it has been assumed this will continue at a constant rate. It is expected this rate will fall as the population of cables of this type diminishes.

Maintenance of the underground cable network is limited to work identified during the visual inspections of cable terminations and exposed earthing cables. Power cables are operated to failure, after which sections are repaired, or replaced as indicated by previous fault history.

6.3.15 Earthing systems

All installations with conductive equipment have their own dedicated earthing systems.

In general these consist of earth banks of driven pins connected by bare copper conductor.

6.3.15.1 Inspection and test programme

The earthing systems are normally visually inspected for integrity on an annual basis, but with the recent increase in theft of the copper earth cables, the inspection frequency has been increased in some areas. Earth resistance and step and touch potentials where applicable are measured every five years in accordance with Vector standards ENS-0068 and ENS-0076.

A summary of ENS-0068 is given as follows:

- Routine and preventive maintenance:
  - Five yearly - earth system visual inspection and remote earth testing of overall earthing system resistance, each earth bank resistance, and step and touch voltage measurement. Marginally compliant sites require step and touch voltage retesting using off-frequency injection current; and
  - Five yearly - ground based visual inspection of tank, bushings, support structure, desiccant breathers and vents, mounting fasteners, signage, clearances, wildlife and vegetation.
- Refurbish and renewal maintenance:
  - Non-compliant earthing locations may require additional electrodes, asphalt patching, gradient rings, equipotential grids, fenced or non-conductive enclosures or wider network solutions such as neutral earthing resistors;
- Fault and emergency maintenance:
  - All identified defects that pose an unsafe condition for public and property require immediate repair, replacement or isolation.

A summary of ENS-0076 is given as follows:

- Routine and preventive maintenance:
  - Annual – temporary earthing equipment, general visual inspection of leads and clamps, earthing lead contact resistance measurement;
  - Annual – earth system visual inspection, physical assessment of above ground earth conductors and connections and tags; and
  - Five yearly - earth system visual inspection and testing, bonding resistance measurements between primary assets, control cabinets and support structures to reference earth bar/grid, remote earth testing of overall earthing system resistance and independent main earth resistance testing if accessible, and step and touch voltage measurement using off-frequency heavy injection current.

6.3.15.2 Maintenance, Refurbishment and Replacement Programme

Earthing cables are only maintained if they are visibly unsound, missing, undersized or test results fall outside the limits given in Vector's distribution earthing maintenance standard.

Predicted future expenditure is based on the assumption the replacement/refurbishment rate will continue at the present rate.

6.3.16 HV Pole Mounted Cable Terminations

Terminations are the connection points between underground cables and the overhead network and include all 6.6 kV, 11 kV, 22 kV and 33 kV pole terminations. There are different types of these terminations in service.

Table 6-20 below shows the breakdown by voltage class, network and value of HV pole terminations on the networks.

Population	33kV	22kV	11kV	6.6kV	Total
Southern	15	2	2555	107	2679
Northern	180	0	5480	0	5660
Total	195	0	8035	107	8339

Book Value	33kV	22kV	11kV	6.6kV	Total
Southern	$0 m	$0 m	$6 m	$0 m	$6 m
Northern	$0 m	$0 m	$9 m	$0 m	$9 m
Total	$0 m	$0 m	$15 m	$0 m	$15 m

Table 6-20 : Riser cable terminations - population and book value

Figure 6-37 and Figure 6-38 provide the age profiles and book values of cable terminations for each region, at the different voltage levels.

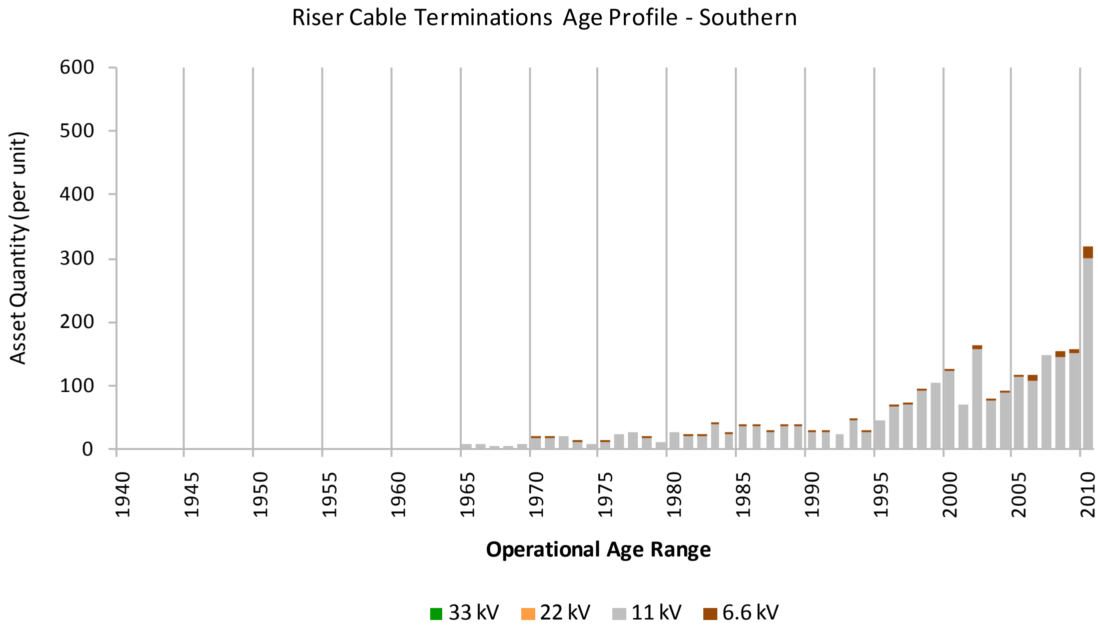


Figure 6-37 : Riser cable terminations age profile – Southern

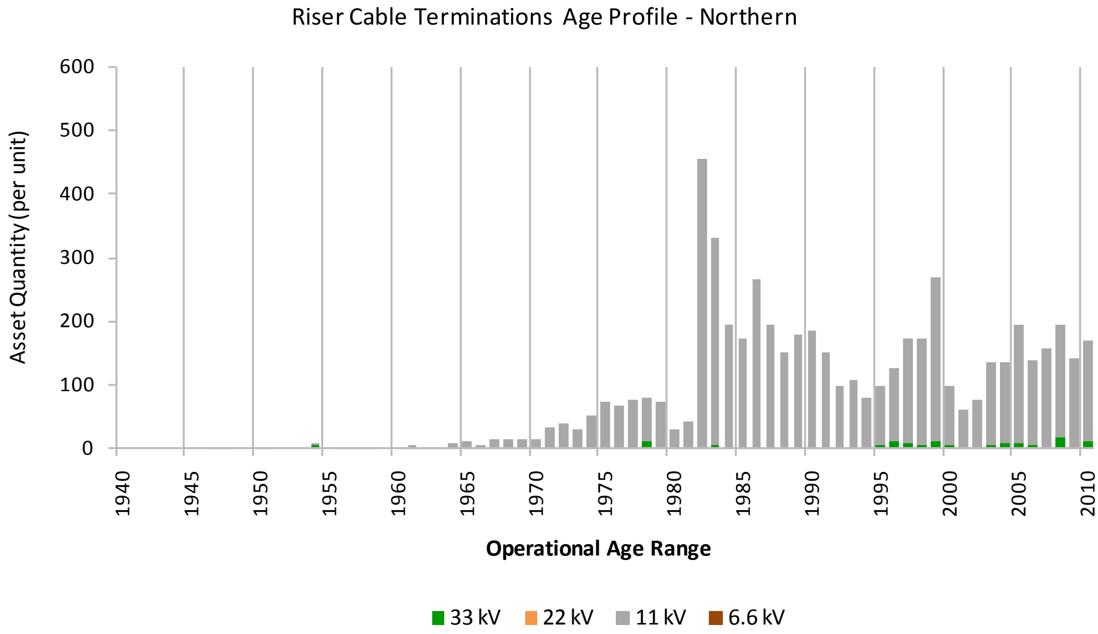


Figure 6-38 : Riser cable terminations age profile – Northern

6.3.16.1 Systemic Issues

Outdoor 3M cable pole terminations installed about 15 years ago are failing. The problem appears to be caused by poor sealing around the lugs, allowing water to enter the termination. Failure of these terminations has been identified as a significant cause of supply interruptions. Although the GIS records show there are only 29 of these terminations still in service, the actual number of failures has not decreased, indicating there are many more still operating. It is planned that the 29 identified terminations will be replaced in 2011/2012. Further replacement progress will depend upon the numbers of terminations identified during the annual network inspection.

Vector is encountering cable pole terminations where the connection between the underground cable and the overhead reticulation jumper is by two lugs bolted together at a standoff insulator. The issue arises at installations where a steel nut or washer has been placed between the two lugs, resulting in a high resistance connection between the underground cable and the jumper. The heating of the nut/washer is sufficient to cause the termination to fail. Terminations of this nature have largely been located and corrected but there are still some in service that were missed during the earlier replacement programme.

Vector's overhead network condition assessment ENS-0187 standard specifically targets the identification of 3M terminations and of interposing nut/washer terminations, to enable us to target their replacement.

Several years ago some PILC cable manufactured with an HDPE sheath was installed. After a short time it was found that Raychem terminations on this cable leaked compound. The vast majority of these terminations were replaced by a pressure resistant termination. Any remaining leaking terminations will be replaced as they are found.

Older terminations were contained in a cast iron enclosure. This changed to cast aluminium and finally to hot shrink or cold applied alternatives. Because of safety concerns regarding the cast metal terminations, they are being steadily removed from the Vector network. All cast metal HV terminations identified in Vector's GIS have been replaced with a heat shrink alternative.

<u>Inspection and Test Programme</u>

Inspection of pole mounted cable terminations is included in Vector's annual overhead network condition assessment ENS-0187 standard. There is no regular testing of cable terminations. A summary of ENS-0187 is given as follows:

- Routine and preventive maintenance:

  <u>Annual inspection</u>

  - All cable risers, terminations and their protection covers shall be inspected as follows:
  - Terminations and supports secure, undamaged and free from corrosion, no visible leaks of insulating compound or oil;
  - All HV cable pole terminations shall be visually inspected to confirm a nut and/or washer has not been inserted between the two cable lugs on the stand off insulators/arresters;
  - Electrical connections including earthing secure, undamaged and not showing signs of overheating;
  - The locations of all HV 3 core 3M cable terminations shall be noted;
  - LV XPLE cables shall be visually inspected to confirm that ultra violet protection shrink tube has been installed over the XPLE insulation of the cores above the break-out udder;
  - Cable covers or pipe not damaged; and
  - Cables securely attached to the pole.
- Refurbish and renewal maintenance:
  - Any identified defect that renders an unsafe situation to the public or property is repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating the unsafe situation.
- Fault and emergency maintenance:

- o Any identified defect likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.17 Pillars and Pits

Pillars and pits provide the point for a customer cable to connect to Vector's reticulation network. They contain the fuses that isolate the service cable from the network distribution cable and which prevents major potential damage to the service cable following a fault in the consumer installation.

For loads up to 100 Amp, an underground pit has largely superseded the above ground pillar for new work, although there are still some applications where a pillar will be preferred. Pits are manufactured from polyethylene, as are most of the newer pillars. Earlier pillars have made use of concrete pipe, steel and aluminium.

The older aluminium pillars are generally adequate for their purpose although many have suffered knocks and minor vehicle impact.

Installation of pits began about ten years ago and comprehensive inspections to date have not shown up any significant maintenance issues.

Table 6-21 provides a summary of the total pillars and pits in use on the Vector network. This includes service and link pillars, service pits (Total Underground Distribution System (TUDS)) and underground network link boxes.

Network	Population	Book Value
Southern	81029	$57 m
Northern	23469	$30 m
TOTAL	104498	$87 m

Table 6-21 : LV pit and pillar - population and book value

Figure 6-39 and Figure 6-40 show the pillar and pit age profiles and book values for each region.

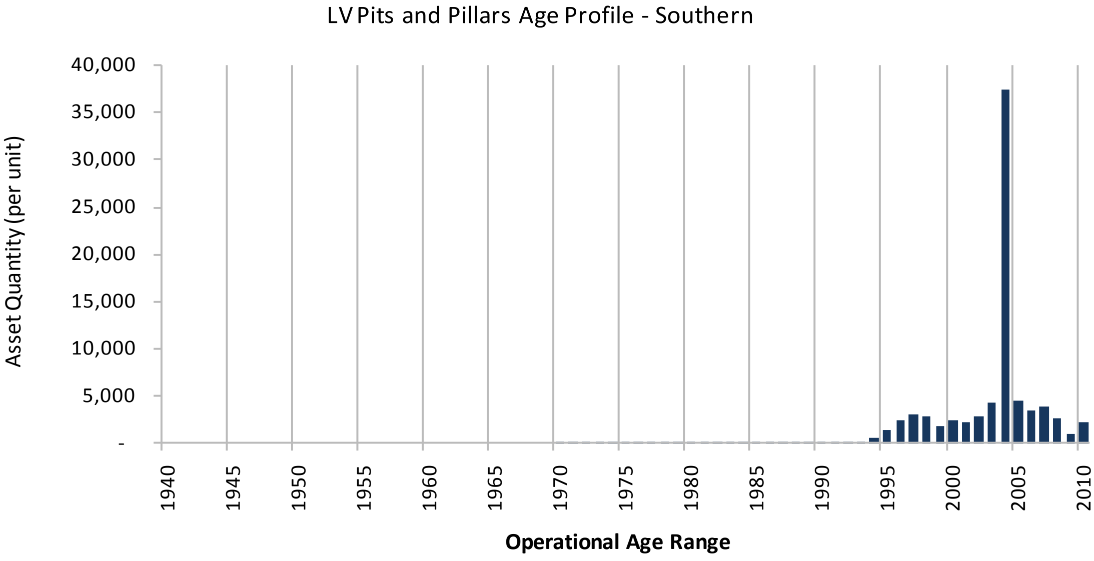


Figure 6-39 : LV pits and pillars age profile - Southern

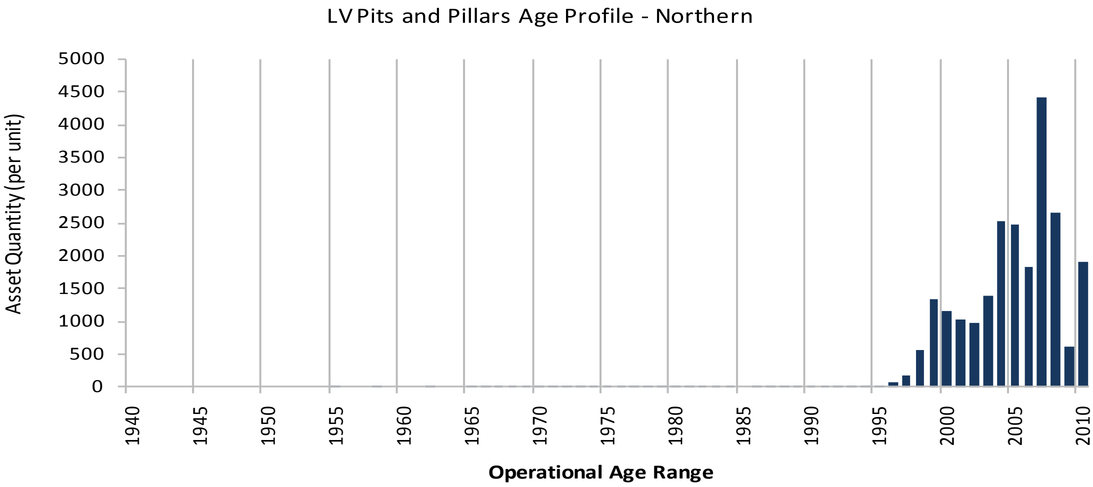


Figure 6-40 : LV pits and pillars age profile - Northern

6.3.17.1 Asset Condition

The condition of customer pits and pillars range from very poor to new condition. The age and range of installation condition is such that it is difficult to determine any primary cause for deterioration. Unsound units are identified through proactive inspection and maintenance programmes and are replaced accordingly.

Mushroom pillars are found in the Northern region and are being replaced for safety reasons. These pillars are being systematically replaced by a polyethylene pillar with similar dimensions.

Underground low voltage network link boxes used in the Auckland CBD are generally in poor condition and require replacement. Also many of the pavement lids and their supporting surrounds have been damaged. Off the shelf like for like replacements are not available for any of this equipment and replacement options are being researched.

6.3.17.2 Inspection and Test Programme

Pillars, TUDS and underground network boxes are inspected at three-yearly intervals as specified in Vector standard ENS-0175.

Loop impedance is measured when service pillars and pits are first installed, but there is no regular testing of these components of the distribution system.

A summary of ENS-0175 is given as follows:

- Routine and Preventive Maintenance:
    - Three yearly – visual inspections, encompasses the following asset, pillars, pits, link boxes, network boxes and fuse boxes. External inspection to ensure safe operation and emergency assessment of vegetation ingress, build up around assets, burial of assets, vandalism. Internal inspection covering loose or poor connections, water ingress, heating effects;
- Refurbish and Renewal Maintenance:
    - Vegetation that cannot be easily removed or trimmed may require the relocation of the affected pit or pillar;

- o Buried or low seated pillars are uncovered and raised. In some cases they may require relocation;
- o Assets on private property that exhibit identified defects and require repair or replacement are relocated to the road reserve;
- o A pillar due for relocation or replacement will be assessed for suitable pit replacement depending on number of circuits and required capacity for; and
- o Minor repairs on site include removal of vegetation, replacement of lid screws, new connectors, corrosion treatments, repainting.

- Fault and Emergency Maintenance:
  - o Hazardous defects identified resulting in potential unsafe situations for public or property, are repaired, replaced or isolated immediately.

6.3.17.3 Maintenance, Refurbishment and Renewal Programme

The remaining life of a pillar or pit is difficult to predict because it is dependent upon a number of factors. These are the pillar construction, natural environment, public access and the electrical loads supplied by the pillar.

Data now being collected under the MUSA agreements with our FSPs, enacted in November 2009, will in future allow a more accurate assessment of replacement programmes. Given the frequency of the preventative maintenance regime, exhaustive data will be available by late 2012. In the interim, predicted replacement expenditure is based on the assumption that replacement rate will continue at present rates.

Pillars are normally operated to failure. This is the operation until they fail the inspection criteria, which are generally based on whether the condition of the pillar is creating a hazard.

Where practicable, pillars are repaired on site following faults or reports of damage or the results of the inspection programme. Otherwise a new pillar or pit or network box is installed.

With the exception of the mushroom pillars there is no general replacement programme. Pillars with a high likelihood of future repeat damage by vehicles are replaced with pits. Older pillars are targeted for planned replacement as repair becomes impractical or uneconomic, or where they present an unacceptable safety risk.

Full replacement of the remaining identified mushroom pillars, is planned for FY12. Should ongoing network asset surveys identify additional mushroom pillars these will be replaced in FY13.

Replacement of underground network boxes has been included as a separate budget item. At present, there is no history of such replacement, and a small provisional sum only is allowed over the next five years.

6.3.18 Distribution Transformers

Distribution transformers convert distribution voltage levels (typically 22kV, 11kV and 6.6kV) to customer voltage levels (typically 400V three phase or 231V single phase). The units are generally constructed with an off-load tap changer, which enables the LV output to be raised or lowered depending on system requirements.

For the majority of distribution transformers currently in service, the windings, insulated with paper insulation, are contained in a tank of mineral insulating oil. For a very small number of transformers, the windings are contained in a tank of synthetic organic ester. These transformers are used in situations where fire safety or protection of the environment (where other containment measures are not practical) are primary considerations.

The windings are made of copper or aluminium wire or foil. The heat generated by a transformer is removed by the ambient air passing over the transformer tank and circulation of the oil through the radiators that are also cooled by the ambient air.

New transformers are supplied in compliance with Vector's standard ENS-0093. Vector's distribution transformers are generally 11kV/415V and rated between 15kVA and 1,000kVA. All the transformers in that range are three phase. There are also a small number of single phase transformers rated at 1.5kVA, 5kVA, 7.5kVA, 10kVA, 15kVA and 30kVA. The three phase transformer windings are connected delta/star in accordance with the vector group reference Dyn11.

Transformers are either ground or pole mounted. Ground mounted transformers are either stand-alone, enclosed in metal or fibreglass canopies, installed in open enclosures or installed in a building. They can be further categorised into industrial, cubicle or package types. The majority of 11kV ground mounted transformers are connected to the MV and LV networks by cable lugs and bolted connections to the transformer bushing flags.

All cubicle style transformers that are installed as part of overhead improvement projects are connected to the HV cables by dead-break screened plug-in cable connectors. The connection to the LV cables is through cable lugs and bolted connections to the transformer bushing flag.

Pole mounted transformers are installed on single or double poles. The transformers are connected to the HV and LV networks by cable lugs and bolted connections to the transformer bushing flags.

In the development of the 22kV underground distribution networks in the Auckland CBD and Highbrook Business Park, 22kV/415V ground mounted transformers are being installed. Transformers for these two networks are three phase and are rated between 300kVA and 1,000kVA. The transformer windings are connected delta/zigzag in accordance with vector group reference Dzn2. The transformers are connected to the HV cables by dead-break screened plug-in cable connectors. The connection to the LV cables is by cable lugs and bolted connections to the transformer bushing flag.

Transformers installed on the network are presently supplied by either ABB or ETEL.

The ODV life for transformers that are 15kVA or less is 45 years and for all other transformers is 55 years. The design life, however, is typically 25 to 40 years based on loading, and if a transformer is well maintained this life can be extended to 60 years or more.

The age profiles and book values of Vector's distribution transformers on each network are shown in Table 6-22, Figure 6-41 and Figure 6-42.

Network	Population	Book Value
Southern	8423	$85 m
Northern	12473	$86 m
TOTAL	20896	$171 m

Table 6-22 : Distribution transformer - population and book value

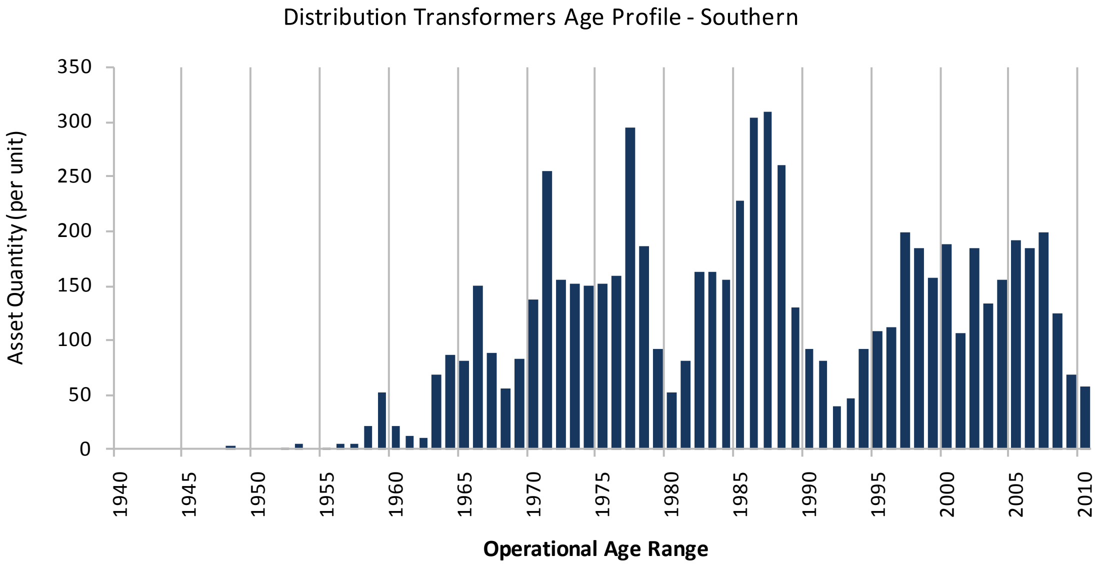


Figure 6-41 : MV transformers age profile – Southern

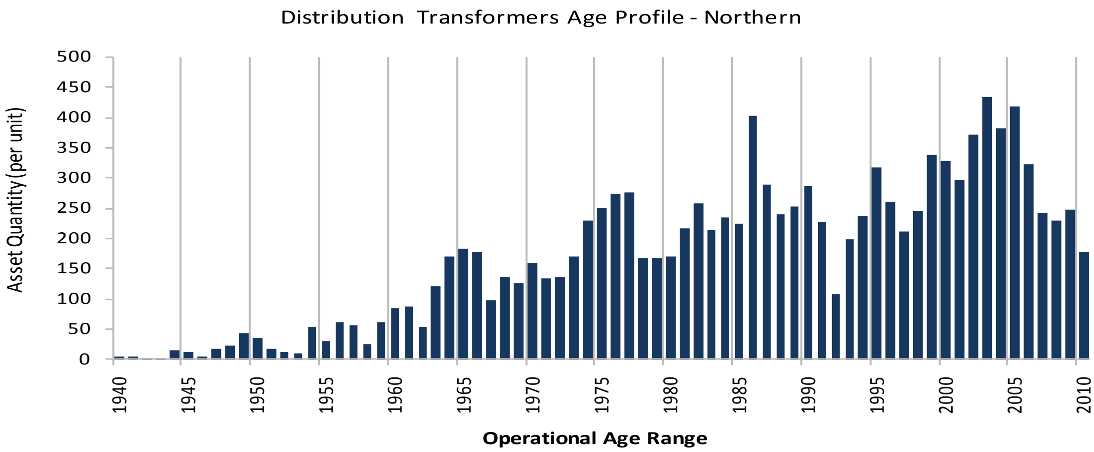


Figure 6-42 : MV transformers age profile - Northern

6.3.18.1 Asset Condition

In general the condition of the distribution transformers is good. Since 2001 many of those that were in poor condition have been replaced as part of renewal programmes which have been implemented across the network.

A systemic issue with corrosion and oil leakage leading to premature asset replacement has, however, been identified with some types of units:

- Some transformers installed between 1998 and 2001 have been identified as prematurely rusting. This is estimated to be about 2% of the population;

- Ground mounted transformers about 25 years old have increased risk of non-compliance due to excessive rust or oil leaks. This is estimated to be about 5% of the population; and
- A greater number of mini substations installed on the Northern network have corrosion issues compared to those on the Southern network. The reason is thought to be the manufacturer's inadequate preparation of the steel surface prior to painting and the subsequent inferior painting coating system.

These transformers are being systematically replaced in accordance with Vector's current renewal process.

6.3.18.2 Inspection and Test Programme

Visual inspection of distribution transformers is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is presently five-yearly for pole mounted transformers and four-yearly for ground mounted transformers.

Electrical testing is not carried out on distribution transformers unless there is a specifically identified issue that needs to be investigated and resolved.

In late 2007 and early 2008 a trial testing of the oil in ground mounted transformers was carried out at nine major customer sites. Analysis of the oil test results showed that of the nine locations, seven transformers were in good condition and the other two required further internal transformer investigation. It was not considered economically worthwhile to extend the trial and it was not continued.

Testing of the insulating oil in a customer transformer for the presence of polychlorinated biphenyls (PCB) is carried out on request from customers and customers' insurance companies. All the test results to date have shown less than 50 parts per million of PCB in the oil. This result means that the oil is classed as a non-PCB liquid.

Thermal imagining and testing for partial discharge (PD) is presently carried out on only ground mounted transformers as part of the transformer inspection programme.

6.3.18.3 Maintenance, Refurbishment and Renewal Programme

Maintenance on distribution transformers is on a time-based inspection regime carried out in accordance with Vector Standard ENS-0051. Onsite repairs are generally minor and include such items as oil top up, replacement of holding down bolts, repair of minor oil leaks, minor rust treatment and paint repairs. Where it is uneconomical or impractical to complete onsite maintenance, or the transformer poses a safety or reliability risk before the next inspection cycle, the transformer is replaced and, where economic, refurbished and returned to stock.

In general Vector's approach is to assess the condition of distribution transformers and proactively replace these based on the assessment (or where a change in capacity is required).

Transformers removed from service that are still in salvageable condition are assessed and refurbished if the assessment criteria to refurbish are met. The assessment also includes consideration of Vector's stock requirements at the time. The assessment criteria are detailed in Vector Standard ENS-0170. It is expected a transformer will attain another 25 to 30 years of service after refurbishment. Transformers that do not meet the assessment criteria for refurbishment are scrapped.

Data obtained from inspections and tests was previously managed and analysed by Vector's FSPs. In December 2010 Vector's Technical Asset Management (TAM) register was commissioned and analysis of the data progressively obtained from Vector's FSPs under the MUSA agreements will now be carried out by personnel in

Vector's AI group. The analysis will form the basis of future replacement programmes.

6.3.19 Auto Transformers and Phase Shifting Transformers

An auto transformer is an electrical transformer with only one winding. A portion of the winding is common to both the primary and secondary circuits. The winding has at least three electrical connection points called taps. The voltage source and the load are each connected to two taps. One tap at the end of the winding is a common connection to both circuits (source and load). Each tap corresponds to a different source or load voltage.

A phase shifting transformer is a transformer that creates an output voltage with an altered phase angle compared to the input voltage, but with the same amplitude.

There are five ground mounted auto transformers and one phase shifting transformer on Vector's network. All are installed on the Southern network. Four of the auto transformers are 11kV/6.6kV and one is 22kV/11kV. The 11kV/6.6kV auto transformers are used in various locations on the Southern network as connections between the 11kV and 6.6kV networks. Their capacities are 3.81MVA (2), 4.58MVA and 6.0MVA.

The 22kV/11kV 1.5MVA auto transformer is used as a backup supply from Counties Power to the Vector network in East Coast Road, Kaiaua.

Auto transformers installed on the network have been supplied by ABB, Astec and Wilson. The year of manufacture for the 11kV/6.6kV auto transformers ranges between 1966 and 1987. The year of manufacture for the 22kV/11kV auto transformer is 2001. The economic life for auto transformers and the phase shifting transformer is 55 years. An age profile and book value of Vector's auto transformers and the phase shifting transformer is shown in Table 6-23 below.

Network	Year of Manufacture	Population	Book Value
Southern	1966	1	$0.02m
Southern	1986	1	$0.02m
Southern	1987	1	$0.02m
Southern	2001	2	$0.06m
Southern	2006	1	$0.18m
Total (units)		**6**	**$0.29m**

Table 6-23 : Auto transformer and phase shifting transformer population and book value

The condition of the 11kV/6.6kV auto transformers is fair. These transformers will be either sold or scrapped when the remaining 6.6KV network is changed to 11kV. The voltage change is planned for completion in May 2011.

The condition of the 22kV/11kV auto transformer is very good.

The 5MVA 11kV/11kV phase shifting transformer was manufactured by Pauwels in 2006. It is installed in the Southern region and is used as a connection point between the Southern and Northern distribution networks. Its condition is very good.

6.3.19.1 Inspection and Test Programme

Inspection of auto transformers and the phase shifting transformer is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is the same as that for ground mounted distribution transformers; currently four-yearly.

Electrical testing is not carried out on the auto transformers and phase shifting transformers, unless there is an issue with a transformer which needs to be investigated and resolved.

Thermal imaging and PD and acoustic discharge testing is presently carried out as part of the inspection programme.

Transformer Condition Analysis (TCA) on oil samples from the auto transformers are presently carried out. It is proposed that this test for the phase shifting transformer be added to the activities carried out by the FSPs. Results of the tests would be supplied by Vector's FSPs under the MUSA. Analysis of the results would assist in determining maintenance and refurbishment programmes for the 22kV/11kV auto transformer and the phase shifting transformer.

6.3.19.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of the auto transformers and phase shifting transformer is on a time-based inspection regime and is carried out in accordance with Vector standard ENS-0051. Onsite maintenance is generally minor and includes such items as oil top up, minor rust treatment and paint repairs.

There is no refurbishment programme for the 11kV/6.6kV auto transformers as they will be sold or scrapped after the remaining 6.6kV network is changed to 11kV. Due to the relatively young age of the 22kV/11kV auto transformer and the phase shifting transformer, their good condition and their economic life, there is currently no refurbishment programme for these units.

There is no replacement programme for auto transformers or the phase shifting transformer.

6.3.20 Voltage Regulators

A voltage regulator is a device that automatically produces a regulated output voltage from a varying input voltage. The regulators on Vector's network are step-voltage regulators and a tap changer in the regulator is used to achieve the regulation.

Voltage regulators are installed at two sites on the Southern network and two sites on the Northern network. All the voltage regulators installed on the network have been supplied by Siemens.

Southern network - there are three single phase 11kV 220kVA ground mounted regulators which are connected in closed delta at one site. At the other site there are two single phase 11kV 220kVA ground mounted regulators connected in open delta.

Northern network - there are two single phase 11kV 165kVA pole mounted regulators which are connected in open delta at one site. At the other site there is a three phase 11kV 417kVA ground mounted regulator.

The ODV life for regulators is 55 years. The age profile and book value of Vector's voltage regulators on each network is shown below in Table 6-24.

Network	Year of Manufacture	Population	Book Value
Southern	1997	5	$0.35m
Northern	2001	2	$0.08m
Northern	2007	1	$0.61m
TOTAL (units)		**8**	**$0.61m**

Table 6-24 : Voltage regulator population and book value

The mechanical condition of the regulators on the Southern network is poor as both sites are located close to the coastline, resulting in increasing corrosion on the regulator tanks and controller boxes. The electrical condition, however, is good.

The mechanical condition of the single phase regulators on the Northern network is fair. There is some corrosion on the regulator tanks and the controller boxes. The electrical condition of all the regulators is good.

Following a switching incident in June 2009 the three phase regulator was removed from service. It is presently being repaired.

As noted, corrosion of the regulator tanks and the controller boxes is occurring on all the voltage regulators. All the single phase regulators will need to be removed from service and refurbished. The work will be carried out under corrective maintenance. The manufacturer has acknowledged there were issues with the painting process at the factory. Recovery of the refurbishment costs will be pursued with the manufacturer.

6.3.20.1 Inspection and Test Programme

Inspection of voltage regulators is carried out in accordance with Vector standard ENS-0188. The frequency of inspection is four-yearly.

Electrical testing is not carried out on voltage regulators unless there is a specific issue that needs to be investigated and resolved.

Thermal imaging is presently carried out on ground mounted voltage regulators as part of the inspection programme.

Transformer Condition Analysis (TCA) on oil samples from the voltage regulators is not presently carried out. It is proposed this test for the phase shifting transformer be added to the activities carried out by service provider.

6.3.20.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of voltage regulators is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0061. Onsite maintenance is generally minor and includes such items as oil top up, minor rust treatment and paint repairs.

Presently there is no refurbishment programme for voltage regulators as they are relatively new (1997 being the oldest installation).

Again, as the voltage regulators are quite new, it is expected that the existing installations will be on the network for some time (20 or more years) and as such there are no planned replacement programmes.

6.3.21 Ground Mounted Distribution Switchgear

Ground mounted distribution switchgear operates at 22kV, 11kV or 6.6kV and is installed in buildings or enclosures on road reserves and private property. It excludes the switchgear in the zone substations. Ring main units, isolators, composite units and CBs are used to connect underground cables. Fused switches and CBs are used to protect distribution transformers. Switches may be operated manually or by a motorised mechanism.

New switchgear is supplied in compliance with Vector Standard ENS-0090 or ENS-103.

Vector's distribution switchgear comprises oil, SF_6 and resin insulated equipment of varying ages and manufacturers. The arc-quenching mediums used in the equipment are air, oil, SF_6 and vacuum. The majority of the switchgear is rated at 11kV with small quantities of 6.6kV and 24kV units. 24kV rated SF switchgear is installed on the 22kV distribution networks in the Auckland CBD and Highbrook Business Park. Definitions of the various categories of switchgear on the network are detailed in Table 6-25 below, while the manufacturers and models of the types used are detailed in Table 6-26.

Switchgear Type	Description
Oil-filled	Primary insulation and arc-quenching mediums are oil.
Solid Insulation	Primary insulation medium is resin and arc-quenching medium is air.
Disconnect Units	As per solid insulation, but without live switching capability.
Sulphur Hexafluoride (SF_6)	Primary insulation medium is SF_6, arc-quenching medium is SF_6 or vacuum.

Table 6-25 : Distribution switchgear categories

Switchgear Type	Manufacturer	Series – Switchgear
Oil-filled	Andelect	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ASTEC	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 1 SD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 2ASD – SDAF, SDAF3, SD, SD2, SD3
	ABB	Series 2BSD – SDAF, SDAF3, SD, SD2, SD3
	Long & Crawford	GF3, ETV2, J2, J4, T4GF3, ALD2P
	Lucy Co	FRMU (Mk 1A)
	Statter	
Solid Insulation	Holec	Magnefix, Hazemeyer
Disconnect Units	Frank Wilde Ltd	FTCE
Sulphur Hexafluoride (SF_6)	ABB	SafeLink, SafePlus (24kV)
	Schneider	Ringmaster, RM6
	Ormazabal	GA

Table 6-26 : Switchgear type, manufacturer and model

Vector has decided to terminate the installation of oil-filled switchgear. In future all distribution switchgear installed on the network will be switchgear that has a primary insulation medium of SF_6 and an arc-quenching medium of SF_6 or vacuum. A contract for the supply of Schneider FBX-E 24kV SF6 switchgear has been agreed and delivery is expected to commence in late March 2011.

GIS records indicate there are 9,627 distribution switch units on Vector's network. (Note that a unit is defined as a maintainable tank i.e. an ETV2, J4 and SDAF are each one tank, as is an SDAF3, GF3 and T4GF3. For solid insulation type switchgear, a cabinet containing multiple cable units and a fuse unit is defined as a maintainable tank.) The ODV life for switchgear is 40 years. Table 6-27 provides a summary of the number of switchgear units on the network, as well as their book value.

Population	22kV	11kV	6.6kV	Total
Southern	184	7552	125	7861
Northern	0	1766	0	1766
Total	184	9318	125	9627

Book Value	22kV	11kV	6.6kV	Total
Southern	$2 m	$48 m	$1 m	$51 m
Northern	$0 m	$19 m	$0 m	$19 m
Total	$2 m	$67 m	$1 m	$70 m

Table 6-27 : Distribution switchgear population and book value

An age profile of Vector's ground mounted distribution switchgear on each network is shown below in Figure 6-43 and Figure 6-44.

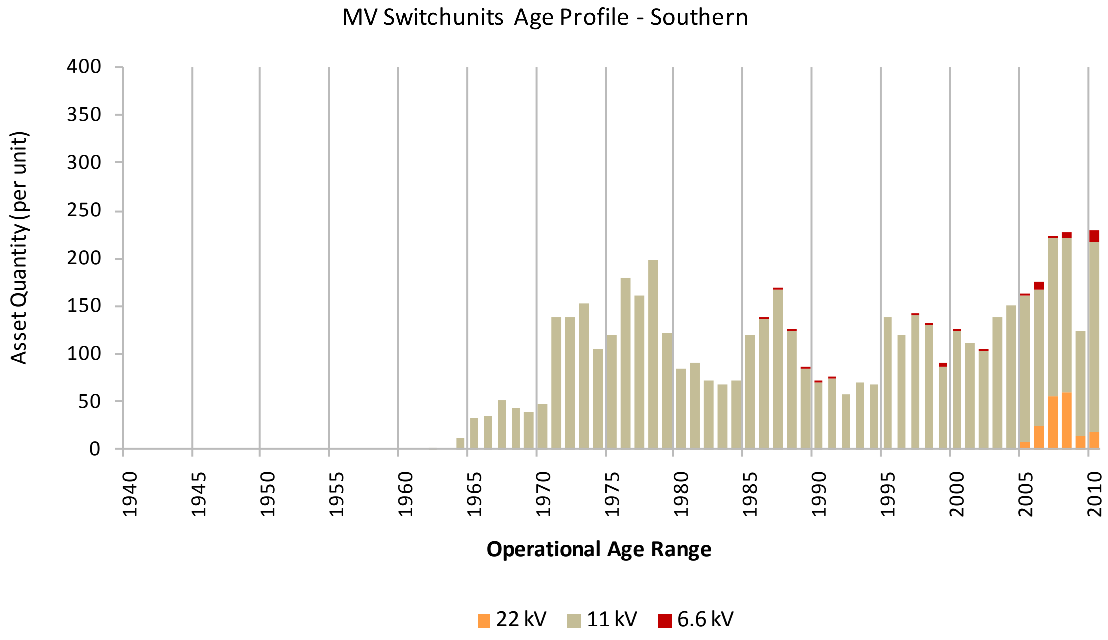


Figure 6-43 : MV switch unit's age profile - Southern

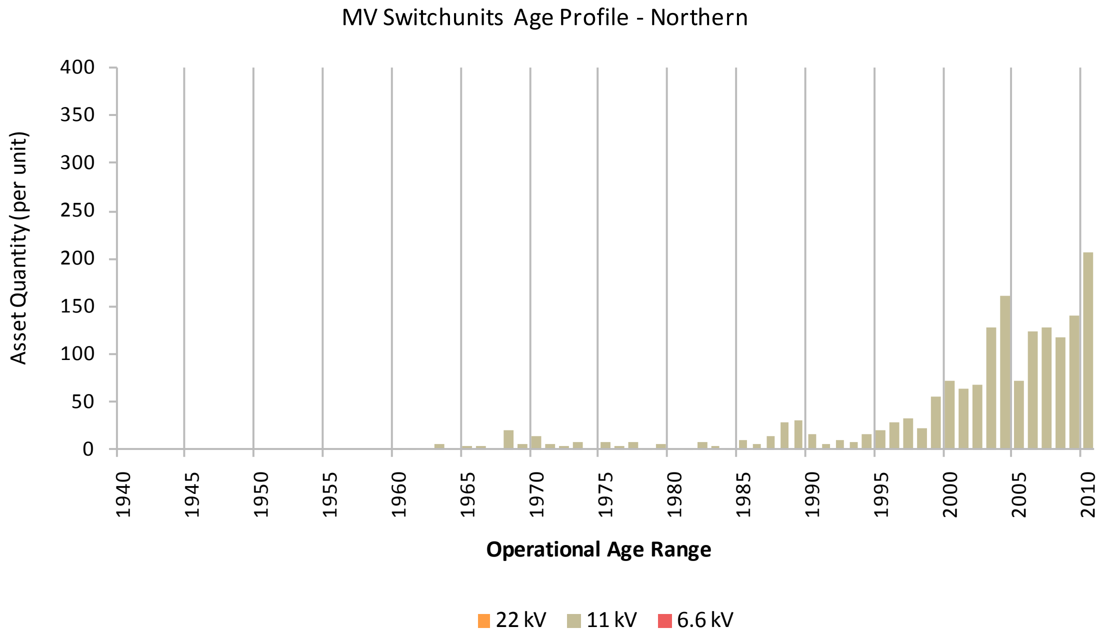


Figure 6-44 : MV switch unit's age profile – Northern

6.3.21.1 Asset Condition

In general the condition of switchgear is good although there are oil-filled SD units whose mechanical condition, due to corrosion, is poor. Many of those units have been replaced. Additionally, other replacements have been driven by transformer replacement through either being physically attached to a transformer requiring replacement or, where there is synergy opportunity to replace the switchgear, during other work. Other general causes for replacement are minor oil leaks and, to an even lesser degree, vehicle damage.

Systemic issues leading to premature replacement (or parts) of the assets include the following:

- Corrosion of the base of SD oil-filled switchgear, particularly where the switchgear contacts the precast concrete foundation, is the main reason for switchgear replacement. The issue has been investigated over the past year and a root-cause analysis is being carried out to determine the solution. A report on the cause and solutions is due to be completed in January 2011. Early indications are the main contributor to the rusting is the calcium hydroxide in the concrete foundation.
- There are considerable numbers of SD fused switches installed on pre-cast concrete pads where movement of the ground under the pad has caused the switchgear to lean to varying degrees. Excessive lean may result in the rear clip of an HV fuse holder in a fused switch not being fully immersed in insulating oil and hence an increased risk of a flashover in the switch. The risk is identified as AIAE3003 on the Asset Investment Engineering risk register.
- There is no indication of the oil level in Andelect Series 1 SD switchgear. A low oil level in a switch unit due to oil leaks could result in an explosion in the unit. The risk is identified as AIAE3042 on the Asset Investment Engineering risk register. Techniques for non-invasive measurement of the oil level in switch units are presently being investigated.

A survey of oil-filled switches on the network is currently in progress, due for completion in March 2011. Results from the survey will be used to determine prioritised remedial and replacement programmes for the SD oil-filled switchgear.

6.3.21.2 Inspection and Test Programme

Inspection of distribution switchgear is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is four-yearly.

Thermal imaging and testing for PD is also carried out as part of the inspection programme. The value of these tests is being reviewed and both may be discontinued in the near future. Present day PD and thermal imaging techniques are heavily dependent on operator skill and interpretation of the results. They are also greatly affected by the environmental and network operating conditions at the time of the test. These tests are not definitive in determining if there is an impending fault, except perhaps in the extreme.

Electrical testing is not carried out on distribution switchgear unless there is a specific issue with a switch unit which needs to be investigated and resolved. However, for oil-filled switchgear that has had an internal inspection and maintenance carried out, a live tank oil sample (LTOS) is taken from a switch unit during the scheduled inspection and analysed. The procedure is carried out in accordance with Vector Standard ENS-0052. The results determine when maintenance needs to be carried out on the internals of the unit or when further oil samples should be taken and analysed.

Testing of the automation of automated switchgear is not currently included in the MUSA with our FSPs and is not carried out. Vector is considering the inclusion of this task in the agreement.

6.3.21.3 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of distribution switchgear is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0052.

Onsite repairs are generally minor and include such items as rust treatment, patching of holes, paint repair, oil top up, and replacement of mounting bolts. Where it is uneconomical to complete onsite maintenance or the switch unit poses a safety or reliability risk before the next inspection cycle, the switchgear is replaced.

Prior to September 2009, oil-filled switchgear that was removed from service was transported to the company that refurbished Vector’s switchgear for assessment and refurbishment or scrapping. This procedure was stopped at the end of September 2009.

In addition to replacement of switchgear due to corrosion or the results of LTOS tests, it is intended to implement a replacement strategy for cast resin and oil-filled switchgear based on a switchgear replacement strategy prepared in 2007. The strategy is based only on the age of the switch units except for the Andelect Series 1 SD switch units. Andelect Series 1 SD switch units have a history of failure and unreliability due to a poor design that cannot be economically rectified.

Approximately 100 Andelect Series 1 SD oil-filled units that are older than 25 years have been identified as top priority for replacement. They are to be replaced in the next two years.

A further 720 Andelect oil-filled units are between 20 and 24 years old and 150 Long and Crawford oil-filled units that are older than 40 years have been identified as high priority replacement items. They are to be replaced over the next five to ten years.

Moderate priority replacements include approximately 680 Andelect oil-filled units that are less than 20 years old and 1200 Long and Crawford units that are between 30 and

39 years old. All the units will be left in service until their condition warrants replacement.

6.3.22 Distribution Equipment Enclosures

Distribution equipment enclosures are used to accommodate Vector's ground mounted distribution equipment. There are many types of enclosures. They are defined as follows:

- Building - a free-standing concrete or concrete block structure with a roof or room housing Vector's distribution equipment;
- Open enclosure - a rectangular structure, without a roof, made of fibre panels, timber, metal, wire mesh or concrete block housing Vector's distribution equipment; and
- Enclosure - a structure, with a roof, made of metal or fibreglass housing Vector's distribution equipment.

The population breakdown for distribution equipment enclosures is given in Table 6-28. An age profile of Vector's equipment enclosures on each network is shown in Figure 6-45 and Figure 6-46.

Network	Population	Book Value
Southern	6866	$45 m
Northern	8218	$21 m
TOTAL	15084	$66 m

Table 6-28 : Distribution Substation - population and book value

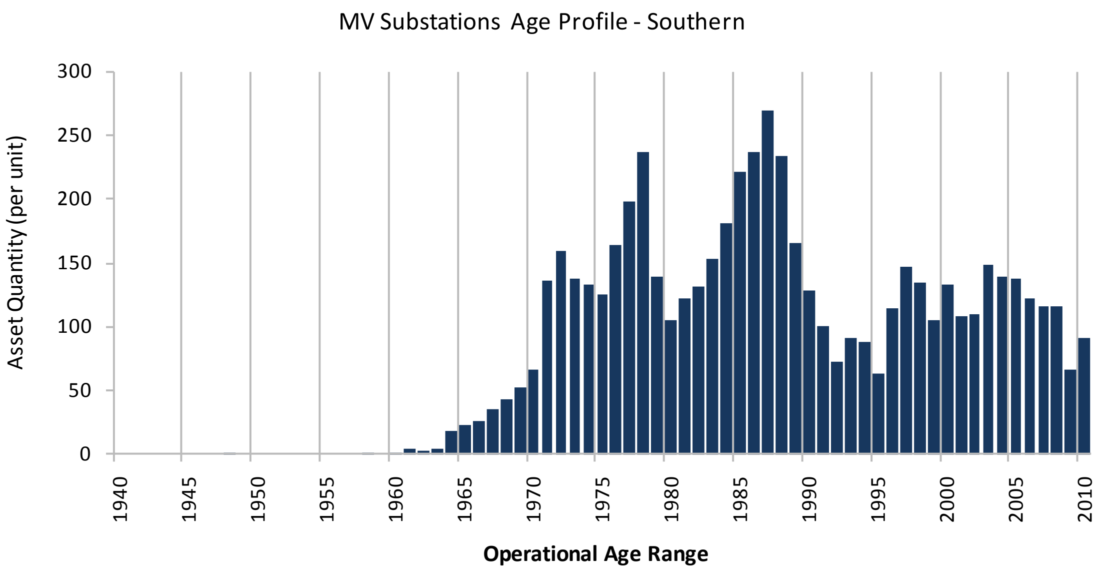


Figure 6-45 : MV substation age profile – Southern

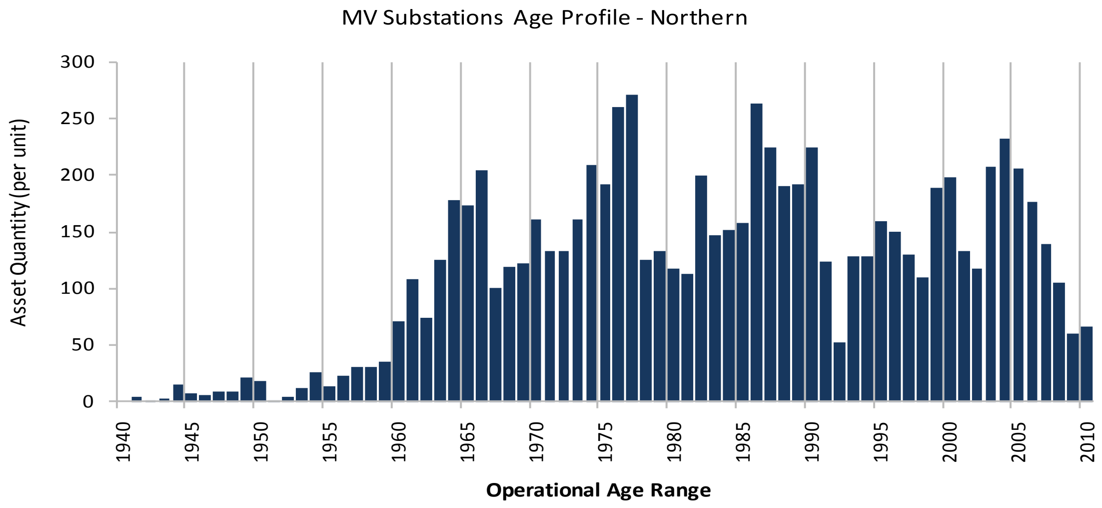


Figure 6-46 : MV substation age profile – Northern

In general the condition of the majority of distribution equipment enclosures is good. There are no systemic issues.

6.3.22.1 Inspection and Test Programme

The frequency of inspection of distribution equipment enclosures is carried out in accordance with Vector Standard ENS-0188. The frequency of inspection is four-yearly.

There is no test programme for the enclosures.

6.3.22.2 Maintenance, Refurbishment and Renewal Programme

Preventative maintenance of distribution equipment enclosures is on a time-based inspection regime and is carried out in accordance with Vector Standard ENS-0053. Repairs are generally minor.

There is no refurbishment or replacement programme currently under consideration.

6.3.23 Low Voltage Switchboards and Frames

An LV switchboard consists of a number of fuses or CBs mounted on a panel. The fuses and CBs are connected to cables which supply power and lighting circuits in the building in which the switchboard is located. The LV supply to the switchboard is either single phase or three phases.

An LV frame consists of a number of fuses and solid links mounted on three phase bus bars supported on a frame. There are two types of fusing installed on LV frames - JW type and DIN type. The frame is supplied from the 415V terminals of a distribution transformer via cables connected to the transformer terminals and the solid links on the frame. The fuses are connected to cables which supply customers.

A network standard for the supply of LV frames (ENS-0113) is presently in draft form.

LV frames are presently supplied by Reticulation Development Ltd, Hamer Ltd, EMF Industrial Ltd and ETEL.

The data in GIS is incomplete and all the ages and book values of the LV switchboards and frames are presently unknown. (As noted before, this is a recurring problem on the LV network assets, which is intended to be addressed as part of a general review of the LV network.)

6.3.23.1 Asset Condition

LV switchboards are generally in good condition.

LV frames of both types are generally in good condition.

On both types of frame there have been incidents (overheating and fires) due to a poor connection between an LV cable or bus bar and a fuse.

There have also been operational issues and incidents with JW type LV frames and resultant from those incidents no work is permitted to be carried out on solid links on JW LV frames unless the frame is de-energised in accordance with the design intention. This includes the tightening and loosening of the solid link securing bolts.

6.3.23.2 Inspection and Test Programme

LV switchboards and frames are visually inspected as per Vector Standards.

Thermal imaging is carried out on LV frames every four years.

6.3.23.3 Maintenance, Refurbishment and Renewal Programme

There are no specific maintenance standards or programmes for LV switchboards or frames. The units are generally replaced when they fail.

However, LV frames which are equipped with JW type fusing and solid links are replaced with frames equipped with DIN type fusing when the distribution transformer associated with the LV frame is replaced.

To address the operational constraint identified in Section 6.1 “Asset condition” above, a frame replacement programme is planned to be carried out over the next ten years.

6.3.24 Power Factor Correction Equipment

In the Southern region there is 153MVAr of capacitor banks installed in 25 zone substations. These capacitor banks are connected to the 11kV switchboards at zone substations and are rated at 3MVAr each. Up to three banks are connected to a zone substation. In the Northern area there are 75 pole mounted 11kV capacitor banks each rated at 750kVAr.

The 11KV capacitors in both regions were installed during 1998/99. The pole mounted banks are in good condition. The zone substation 11kV capacitors are in good condition but associated equipment such as enclosures are showing signs of deterioration. The capacitors are housed in weatherproof enclosures. Many of these enclosures are located outdoors, are manufactured from painted mild steel and are rusting. Failures have been caused by water entering the outdoor enclosures. The mounting of the CTs in the enclosures has been causing damage to the potting compound. New CTs and a redesigned mounting system are required. The capacitors at Liverpool have suffered from a reactor fault and require major reconstruction.

The 11kV capacitors located in the Southern region zone substations are in need of maintenance.

6.3.24.1 Inspection and Test Programme

11kV pole mounted capacitors are inspected annually as part of the overhead inspection programme.

11kV and 33kV zone substation capacitors are visually inspected every two months. (Vector Standard ENS-0192).

6.3.24.2 Maintenance, Refurbishment and Renewal Programme

11kV pole mounted capacitors are maintained by cleaning the devices, checking connections and replacing the batteries in the controllers of the switched units at eight yearly intervals. The capacitance of the cans is measured during an eight-yearly maintenance cycle (Vector Standard ENS-0048).

11kV zone substation capacitors are inspected every two years, bushings and filters are cleaned and connections checked. The capacitance of the cans is measured, secondary injection performed on the protection relays, the CBs ductored and insulation resistance measured during a four yearly testing cycle (Vector Standard ENS-0192). The existing pole mounted capacitors are only repaired where salvaged components are available for the repair. The zone substation 11kV capacitors are to be maintained in an operational state.

There is no current planned replacement for the 11kV capacitors.

6.3.25 Energy and Power Quality Metering System

6.3.25.1 Asset Description

There are 53 combined energy and PQ meters installed at Transpower grid exit point (GXP) substations and in Vector's distribution network, primarily at zone substation level (refer Table 6-29 below for breakdown). There are four portable PQ meters. The meters communicate via IP network to the metering enterprise applications.

At GXP level, the meters are deployed to provide check metering function to Transpower's revenue metering installations. The meters are connected to check the metering instrument transformers owned by Transpower. The meters also receive pulse streams from Transpower's metering system and provide comparisons between the two systems.

At the control centre level metering ION Enterprise software is deployed for monitoring of real-time power conditions, analyse PQ and reliability, and respond quickly to alarms to avoid critical situations.

The meters are also configured to detect under-frequency event in the network and initiate load shedding.

Based on the cost of the recently installed projects, the Energy and Power Quality Metering System is estimated to be worth $2 million.

6.3.25.2 Age Profile

These assets have an expected technical life of 15 years. A breakdown of asset ages is provided in Table 6-29.

Network	Type	Year of Manufacturer	Population
Northern	ION 7650	2007	4
Northern	ION 7650	2008	1
Northern	ION 8500	2003	2
Southern	ION 7330	2003	3
Southern	ION 7330	2009	4
Southern	ION 7500	2002	9
Southern	ION 7550	2007	1
Southern	ION 7600	2002	10
Southern	ION 7650	2006	3
Southern	ION 7650	2007	1
Southern	ION 7650	2008	1
Southern	ION 7700	1999	5
Southern	ION 7700	2001	3
Southern	ION 7700	2002	2
Southern	ION 7700	2003	2
Southern	ION 7700	2006	1
Southern	VIP	2002	1
Total (units)			**53**

Table 6-29 : Combined energy and power quality meters

6.3.25.3 Condition of the Asset

The metering assets are in good condition.

6.3.25.4 Maintenance Programme

New meter firmware releases are evaluated for relevance to Vector's meter population and upgrades initiated if required.

The meters and metering system configuration is outsourced and is normally performed remotely. The ten-year cost estimate for maintaining the metering systems is presented in Table 6-30.

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
$0.10m	$0.11m	$0.12m	$0.13m	$0.14m	$0.15m	$0.16m	$0.17m	$0.18m	$0.19m	$0.20m

Table 6-30 : Vector's Network – metering system maintenance costs 2010 to 2020 ($million)

6.3.25.5 Replacement/Refurbishment/Expansion Programme

Vector keeps spare meters in case of meter failures. Based on the performance and failure rate Vector will consider planned replacement of the older generation of the meters from 2015.

Over the next five years it is currently planned to installed 41 new PQ meters at zone substation level and complete installation of PQ meters at GXP Albany, Henderson, Hepburn, Wellsford and future 110 kV Wairau GXP.

Vector's ION Enterprise Energy Management System is currently planned to be upgraded to version 6.0 and additional capabilities in analysing databases of PQ and energy measurements are also currently planned to be implemented over the next three years.

6.3.26 Other Diverse Assets

6.3.26.1 Mobile Generator Connection Unit (MCGU)

Vector owns two MGCUs purchased in 2006 with a current estimated book value of $600,000. The units are used to provide voltage support to the network and to avoid outages at distribution substations during maintenance works.

The MGCUs are mounted in self-contained 20-foot containers on skids for rapid deployment. The MGCUs units provide an interface between the 11 kV network and multiple or single 415V diesel generators. Each unit has the capacity to inject up to 2.5MVA into the 11 kV network connecting to either overhead lines or underground cable networks.

Each MGCU comprises a 2.5MVA transformer, high and low voltage CBs, protection control, monitoring and auxiliary supply. The units are shown schematically below in Figure 6-47.

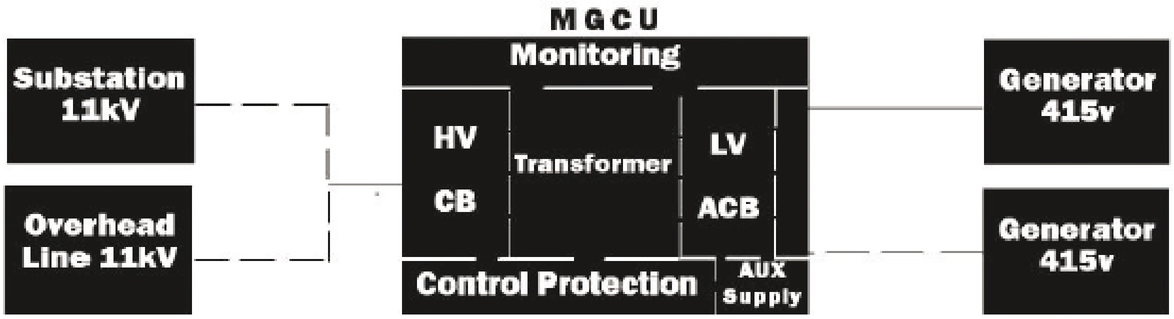


Figure 6-47 : Mobile generator connection diagram

The units are stored at and maintained by NZ Generator Hire.

6.3.26.2 Tunnels

Vector has a number of cable tunnels in its Southern network.

By far the largest single Vector asset is the 9200 metre by three metre diameter tunnel which extends from a shaft in Transpower's Penrose switchyard to the Hobson shaft at Vector's Hobson substation yard. There are access/egress points at the Newmarket shaft at the back of the ex-Vector (now Westfield) site in Nuffield Street and at the Liverpool substation, consisting of three shafts that extend into the basement of the Liverpool substation. The tunnel has a design life of 100-plus years and its present book value is $96.5 million.

The tunnel is primarily a conduit for HV power cables currently operating at voltages of 22 kV, 33 kV and 110 kV. The tunnel has been designed with the capacity to accommodate more circuits than presently installed. All work and maintenance within the tunnel is governed by Vector Standard EOS-018.

The other Vector-owned tunnels are minor in comparison, with the next longest being the Quay Street tunnel which is approximately 1000 metres in length along Quay Street with a 200 metre side tunnel to Emily Place. The Quay Street section is scheduled to be backfilled in 2010 due to concerns over its structural integrity. The cables in this tunnel operating at 11 kV and 22 kV will be run to failure and not replaced, as new circuits along alternate routes have already been established.

The other significant tunnels are:

- Swanson Street Tunnel - approximately 350 metre in length from the Hobson Substation east up Swanson Street;
- Victoria Street;
- North Western Motorway crossing Kingsland; and
- May Road to South Western Motorway crossing.

6.3.27 Cable Ducts

Cables can be directly buried or installed in ducts. When cables are directly buried they have to be installed in a safe manner which allows heat to be dissipated to the surrounding soil as well as buried deep enough to minimise the risk of accidental excavation damage and the effect of solar gain on the ground causing temperature rise and de-rating.

Cable ducts offer the benefit of providing added protection to cables, allowing more flexibility around installation and also simplifying future replacement. Ducts are also installed for future-proofing purposes; making use of construction opportunities and synergies as they arise[8].

However, cable ducts act as insulation to the cable which de-rates them. Often it has also been found that spare ducts have been crushed and are not usable.

Historically, Vector only installed ducts at road crossings, across bridges abutments, railway crossings or when new roads were laid (where a moratorium on later excavation is imposed). As time went on, ducts started to be installed as standard practice when opportunities arose, largely due to the low incremental cost of the materials.

A recent review of the cost of duct installation indicates they may not be as cost effective as they used to be. A review of the spare ducts policy (including the circumstances when spare ducts are to be installed and how these ducts are managed) will be carried out in the next 12 months.

6.4 Spares Policy and Procurement Strategy

Vector's strategic spares guideline EEA-0034 outlines the strategy and policy for the handling and purchase of strategic spares for the purposes of maintaining the electricity supply in the event of a major equipment failure or contingency event.

[8] For example, working alongside other utility providers when they construct new footpaths or roads.

Specifically, strategic spares refer to equipment and or parts that need to be held in store for ready deployment and cannot be obtained in reasonable time due to long delivery periods or obsolescence.

Vector's asset specialists are responsible for determining what items should be held as strategic stock and for re-ordering apparatus when stock levels are less than optimal. When new equipment is purchased for the first time (e.g. a new type of switchboard) an initial stock of manufacturer recommended spare parts is also purchased as part of Vector's strategy.

In practice it is impossible to carry spares for all network equipment. In addition, parts for some aged apparatus are no longer available as the OEM manufacturer no longer exists. Where possible, critical parts are recovered from other assets as reinforcement and replacement projects are undertaken.

In some instances, other market manufacturers have been approached to remanufacture critical parts (such as contacts on early model tap changers).

Lack of spares for key equipment is a risk to the business and efforts to alleviate this by replacing legacy equipment on the networks is part of Vector's asset replacement prioritisation. (Other mitigation plans have also been drawn up, where appropriate.)

6.5 Adopting New Technologies

Vector has a team of asset specialists that approve and review all network fittings and apparatus to be used on the networks. An important function of this work is to look to the market and evaluate new, improved and emerging technologies. Important examples of how this has occurred in practice are discussed below.

6.5.1 Sub-transmission Systems

6.5.1.1 Circuit Breakers and Switchboards

Vector was the first New Zealand network operator to adopt fixed pattern technology for its MV indoor zone substation switchboards. Specifically, new switchboards must comply with Vector equipment specification ENS-0005 and to IEC 62271. This specification was chosen due to its high level of operator safety and long periods between maintenance activities. Coupled with modern relaying and control systems, the modern zone substation has little need for operator intervention over its design life. This life is primarily based on life-time fault operations rather than traditional time-based parameters.

In addition, equipment complying with these specifications is also rated to contain faults and contains no oil or other combustible products. This makes equipment complying to these specifications some of the safest in the world today.

6.5.1.2 Power Transformers

The basic transformer construction materials and methodology has changed little over the past 100 years (notwithstanding significant improvements in insulating oils and manufacturing techniques). However, there have been developments in control monitoring and tap changing technologies.

Vector is currently evaluating the long-term cost-benefit of advancements in technologies such as vacuum tap changers, on-line PD and key gas monitoring technologies. Vacuum tap changers are a continuation from VCB technology developed over the past 20 years.

The newest technologies available today use SF_6 gas in place of mineral insulating oil. This technology, however, is very expensive and specialised and has thus far been regulated to the HV VHV (220 kV and above) levels and is not likely to be economic for electricity distribution networks for many years.

For Vector, traditional oil-filled transformers with Kraft paper insulation will continue to be the norm in the foreseeable future.

6.5.1.3 MV Cables

The sub-transmission system of Vector's networks comprises of a mixture of cable technologies. These technologies consist of fluid-filled, PILC, gas pressurised and XLPE cable technologies. Cable construction is also wide ranging from single phase, three phase, steel wire armoured (SWA), submarine and others.

XLPE cables are the preferred construction type worldwide and Vector has taken up this technology as its standard. Vector's current standard is for the installation of XLPE cable up to and including its maximum system voltage of 110 kV.

Changes in joint and termination technologies have advanced over the past 20 years and Vector has adopted some of these available technologies. After product evaluation, Vector has adopted mechanical sheer bolt fault-rated connector technology as well as 'cable plug' connecting systems for all of its MV switchgear apparatus complying with Vector Standard ENS-0005.

6.5.1.4 Protection and Control

Vector has adopted the IEC 61850 protocol. This protocol provides guidance on the series of standards applying to substation automation equipment and systems with an explanation of their structural elements, configurations and basic functions. Vector has selected protection relays, SCADA and control systems complying with this standard. Vector makes extensive use of the functionality offered by new relay systems to not only enhance network protection schemes, but also for monitoring and metering purposes.

Further, Vector is gradually converting its Cu pilot wire system to fibre optics, enabling greater functionality between stations and taking full advantage of the protection and control systems.

6.5.1.5 Buildings and Structures

Vector's networks are experiencing ongoing steady growth. As a result Vector needs to establish several new substations over the coming years. Past practices of engaging architects, builders and designers for a bottom-up design is time consuming, inefficient, expensive and often results in less than optimal outcomes. Recognising this, Vector has put together a small team to establish a new template design for its buildings. This new design covers all aspects of the substation build from construction methodology to primary plant considerations, operator safety, and security as well as community impact considerations. The design has been used on the last several substations and the concept and design has evolved as a result of learning from previous builds.

The team is close to publishing the template base of design as a new Vector standard which will be used for all new zone substations. Use of this template will provide benefits through ease of construction, standardisation of design, robust materials and adherence to long-term design life of the build.

6.5.2 Distribution Systems

6.5.2.1 Transformers

Technology in distribution transformers has been unchanged over the past ten years. However, developments in insulating materials have progressed to address environmental concerns around oil-filled apparatus. Vector has explored the technology available and in environmentally sensitive locations where the effects of fire, smoke and possible run-off into watercourses is an issue.

For these situations, Vector has adopted a synthetic ester (MIDEL 7131) instead of mineral oil as the insulating fluid. MIDEL 7131 is environmentally friendly, fully biodegradable and non-toxic.

6.5.2.2 Oil-filled Switchgear

In an effort to remove oil-filled apparatus from distribution networks, it is planned to issue an RFP for the supply of distribution switchgear containing no combustible materials, in line with Vector's specification for MV switchgears for use on its sub-transmission networks.

6.5.2.3 Partial Discharge

PD measurement in cables and other distribution apparatus can give an indication of the health of the equipment. To date, results have been mixed and it is not possible to say categorically that any equipment with PD above a certain level will fail. The science around PD monitoring and reacting to this is still developing. It may become a useful tool for the prediction of imminent asset failure or faulty equipment in the future.

6.5.2.4 Corona Camera

Corona discharge produces a narrow band of UV radiation. A Corona camera can detect this and has been trialled with the aim of detecting faulty overhead apparatus. This technology has shown some promise but it is dependent on the skill and interpretation of the operator. Like PD, as the technology becomes more developed, it is likely to become a more useful tool for the identification and prediction of imminent failure of OH connected apparatus.

6.6 Undergrounding of Overhead Lines

Vector, through an agreement with its majority shareholder, the Auckland Energy Consumer Trust (AECT)[9], commenced the Overhead Improvement Programme (OIP) in 2001. Through this it aims to underground or make improvements for amenity purpose to the remaining overhead electricity lines across the urban areas of the former Auckland City, Manukau City, and Papakura District.

Through the agreement Vector commenced the programme investing a minimum of $10 million per year on undergrounding in this area. The minimum amount of undergrounding is inflation-adjusted each year by the producer's price index (PPI). The minimum investment targeted for the 2009/2010 year is $12.5 million.

UnitedNetworks, when acquired by Vector in 2003, had embarked on an undergrounding programme in the areas of the former Rodney District, North Shore City, and Waitakere City. This programme was funded through dividends from shares

[9] This is a requirement of the Trust Deed.

in UnitedNetworks held through the Waitemata Electricity Trust for Rodney District Council, North Shore City Council, and Waitakere City Council. The UnitedNetworks Shareholders Society, as trustees of the Waitemata Electricity Trust, was responsible for administering payment for the undergrounding work.

With the councils divesting their UnitedNetworks shares through the sale of the company to Vector and then opting to use the proceeds of the sale of shares to fund other council activities, dividend income to the trust ceased. Vector continued with this programme until the available funds in the trust, approximately $11 million, had been invested through further undergrounding activity. Vector has not been able to justify further investment in the undergrounding of overhead lines across the areas of the former Rodney District, North Shore City, and Waitakere City since funding support from the Waitemata Electricity Trust ceased in 2005.

6.6.1 Criteria for Selecting the Area for OIP

Vector sets its priority for undergrounding based on the condition and performance of overhead lines. Priority is given to undergrounding areas where large investments would otherwise be needed to rebuild overhead lines.

Secondary drivers include (a) the frequency of faults in the area (pole strikes etc), (b) the resulting benefit versus undergrounding costs, (c) the level of other council or utility works planned for the area, and (d) other synergy opportunities that help to reduce overall costs and provide other benefits.

6.6.2 Projected OIP Expenditure

Vector's targeted investment in undergrounding for the 2009/2010 year is $12.5 million. Projected expenditure for undergrounding over the next ten years will be targeted at the same (real) level but adjusted to reflect movements in PPI. The projected expenditure projection over the planning is shown in Table 6-31 below.

Financial Year	2010 /11	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20
Budget Amount ($M)	12.6	9.6[10]	15.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

Table 6-31 : OIP improvement budget

6.7 Renewal Expenditure Forecasts

All asset replacement projects and programmed replacement works have been identified for the review period as outlined in the preceding sections.

To ensure a consistent ranking of project priorities, a prioritisation matrix has been developed that is applied to each identified project. (This applies to the whole capital programme, not just the network integrity-related works). The matrix, in as far as it applies to renewal works, is described in Table 6-32.

[10] Due to factors outside Vector's control, the targeted OIP programme in the 2010/11 financial year is unlikely to achieve the budgeted amount. The 2011/12 proposed budget has therefore been consequentially increased to make up the shortfall in the 2010/11 OIP programme.

Priority Drivers							
Rank	Growth	Integerity	Customer	Legal & Regulation	Health Safety and Environment	Financial & Other	Operational Excellence
1	Capacity breach leading to asset damage	Reactive - critical assets	Utility driven relocations Contractual obligations with major breach consequences	Legal breach Breach technical regulations Serious regulatory breach	Direct, serious safety threat Direct, serious environment threat Mitigation of extreme & very high direct risks Critical cyber-security breach	OIP	
2	Other capacity breaches	Asset condition (1)	Other contractual obligations Other relocations New connections (NPV>0) Capacity increases (NPV>0) Customer funded projects	Regulatory compliance & improvements	Anticipated serious safety issue Anticipated serious environmental issue Mitigation of high direct risks Serious cyber-security breach	Avoiding financial "bleeding" on uneconomic assets Avoid severe reputation risk	IT & information support critical for AI ops
3	Security of supply breach Enhancing network efficiency	Asset condition (2) Power Quality Improvement Technical obsolescence	Addressing (reasonable) customer expectations	Compliance with Vector technical policies & standards	Medium - Term HS&E Improvement Projects	Improved efficiency Allows capex deferral Avoid major reputation risk	IT & information support supporting effective AI ops Pilot projects, testing new initiatives
4	Safeguarding future options	Asset condition (3) Reliability improvements	Other new connections Other capacity increases			Other NPV>0 opportunities Other reputation risks	
5	Nice to have; discretionary; image & brand improvement						

Asset condition (1) = Severe deterioration of asset.

Asset condition (2) = Asset at end of technical life; increased risk of asset failure (and of material consequence), costing more to maintain and operate than to replace.

Asset condition (3) = Steady-state asset replacement programs.

Table 6-32 : Priority matrix for network integrity (renewal and replacement) projects

Based on the renewal requirements described in this section of the AMP, and after applying the prioritisation criteria, the proposed network integrity (asset renewal or replacement) capex programme for the next ten years is presented in Table 6-33.

Region	***Project***	***2011/12***	***2012/13***	***2013/14***	***2014/15***	***2015/16***	***2016/17***	***2017/18***	***2018/19***	***2019/20***	***2020/21***
Southern	*Reliability Improvements - Automated Switchgear*	*$2.65 m*	*$2.65 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*	*$1.25 m*
Southern	*Cable Replace – Auckland*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*	*$1.48 m*
Southern	*Crossarm Replace - Auckland*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*
Southern	*Earthing Upgrades - Auckland*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*
Southern	*Ground Mounted Switchgear Replace – Auckland*	*$1.50 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*
Southern	*Pillar and Pit Replace - Auckland*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*	*$1.39 m*
Southern	*Pole Mounted Switchgear Replace - Auckland*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*
Southern	*Pole Replace – Auckland*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*
Southern	*Reconductoring - Auckland*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*	*$0.41 m*
Southern	*Transformer Replace - Auckland*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*	*$1.74 m*
Southern	*Zone Sub Capacitors Replace - Auckland*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*
Southern	*Conector Replacement*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*	*$0.22 m*
Southern	*11kV Indoor SWBD - Hobson (Brush 1969 - 21 Panels DBL Bus)*				*$2.50 m*						
Southern	*11kV Indoor SWBD Replace - Balmoral (Brush 1964 - 12 Panels)*			*$1.50 m*							
Southern	*11kV Indoor SWBD Replace - Drive (Brush 1968/Southwales - 13 panels)*						*$1.50 m*				
Southern	*11kV indoor SWBD Replace - Freemans (Brush 1967-13 panels)*						*$1.50 m*				

Region	Project	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Southern	*11kV Indoor SWBD Replace - Liverpool Stage I (Brush 1965 - 28 Panels DBL Bus)*										
Southern	*11kV Indoor SWBD Replace - Liverpool Stage II (Brush 1965 - 28 Panels DBL Bus)*	*$2.50 m*									
Southern	*11kV Indoor SWBD Replace - Liverpool Stage III (Brush 1965 -28 Panels DBL Bus)*		*$3.00 m*								
Southern	*11kV Indoor SWBD Replace - Mangere Cent (Brush 1967 - 15 panels)*							*$1.75 m*			
Southern	*11kV Indoor SWBD Replace - Manurewa (Brush 1969 - 13 Panels)*					*$2.10 m*					
Southern	*11kV Indoor SWBD Replace - Maraetai (Southwales 1955 - 11 Panels)*		*$1.75 m*								
Southern	*11kV Indoor SWBD Replace - Onehunga (Southwales 1963 - 12 panels)*			*$1.50 m*							
Southern	*11kV Indoor SWBD Replace - Orakei (Brush 1966)*				*$2.10 m*						
Southern	*11kV Indoor SWBD Replace - Pakuranga (Brush 1969 - 13 Panels)*								*$1.75 m*		
Southern	*11kV Indoor SWBD Replace - Sandringham (Brush 1967 - 18 Panels)*									*$2.00 m*	
Southern	*11kV Indoor SWBD Replace / Retrofit - Manurewa (replace Brush 1967 - 13 Panels - Retrofit 7 Reyrolle LMT to LMVP)*			*$2.10 m*							
Southern	*SWBD Replace / Retrofit*									*$2.00 m*	*$2.00 m*

Region	**Project**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Southern	*11kV Indoor Switchboard Reyrolle Retrofit*	*$0.55 m*									
Southern	*11kV Indoor Switchboard Reyrolle Retrofit*										
Southern	*11kV Indoor Switchboard Reyrolle Retrofit*										
Southern	*11kV Indoor Switchboard Reyrolle Retrofit*	*$0.55 m*									
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (10 Panels)*			*$0.50 m*							
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (10 Panels)*									*$0.60 m*	
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (12 Panels)*								*$0.60 m*		
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (12 Panels)*									*$0.60 m*	
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)*					*$0.65 m*					
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)*						*$0.65 m*				
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)*								*$0.65 m*		
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (13 Panels)*										*$0.65 m*
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (15 Panels)*										*$0.75 m*
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (15 Panels)*				*$0.75 m*						
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (2 panels)*			*$0.10 m*							
Southern	*11kV Indoor Switchboard Reyrolle Retrofit (5 Panels)*						*$0.25 m*				

Region	Project	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Southern	11kV Indoor Switchboard Reyrolle Retrofit (7 Panels)					$0.35 m					
Southern	11kV Indoor Switchboard Reyrolle Retrofit (9 Panels)							$0.45 m			
Southern	22kV Indoor SWBD Replace - Kingsland (AEI 1963 - DBL Bus) Stage II		$2.00 m								
Southern	22kV Indoor SWBD Replace - Kingsland (AEI 1963 - DBL Bus) Stage III			$1.00 m							
Southern	22kV Indoor SWBD Replace - Kingsland (AEI 1963 DBL Bus) Stage I	$0.10 m									
Southern	Hobson Quay Tunnel - Filling V2										
Southern	Power Transformer Replace - Balmoral 22		$4.40 m								
Southern	Power Transformer Replace - Glen Innes 22						$4.40 m				
Southern	Power Transformer Replace - Mount Albert 22				$2.20 m						
Southern	Power Transformer Replace - Onehunga 22			$4.40 m							
Southern	Power Transformer Replace - Parnell 22/11 (2units)					$4.40 m					
Southern	Power Transformer Replace							$2.00 m	$2.50 m	$4.00 m	$5.00 m
Southern	Subtransmission Cable Replace - Balmoral 22	$3.50 m	$3.50 m								
Southern	Subtransmission Cable Replace - Chevalier 22					$6.00 m					
Southern	Subtransmission Cable Replace - Liverpool/Quay 22						$4.00 m				
Southern	Subtransmission Cable Replace - Maraetai (FF) 33		$3.00 m	$3.00 m							

Region	Project	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Southern	*Subtransmission Cable Replace - Mt. Albert*										
Southern	*Subtransmission Cable Replace - Onehunga (22kV PILC ~ 4.5Km)*										
Southern	*Subtransmission Cable Replace - Parnell 22*			*$4.00 m*							
Southern	*Subtransmission Cable Replace - Ponsonby 22*				*$5.00 m*						
Southern	*Subtransmission Cable Replace - Sandringham 22 (part B)*										
Southern	*Subtransmission Cable Replace - Takanini (1.4km 33kv -PILC)*				*$4.00 m*						
Southern	*Subtransmission Cable Replace*							*$5.00 m*	*$5.00 m*	*$5.00 m*	*$5.00 m*
Southern	*LV Frame Replace*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*
Southern	*Zone Substation Oil Containment - Auckland*	*$0.75 m*	*$0.75 m*	*$0.50 m*	*$0.50 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*
Southern	*Zone Substatation Seizmic Compl - Auckland*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*
Southern	*Strategic Spares - Auckland*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.10 m*	*$0.10 m*	*$0.10 m*	*$0.10 m*	*$0.10 m*	*$0.10 m*	*$0.10 m*
Southern	*Oil-filled Distribution SwitchGear –Replace/Repair (AIAE3003)*	*$0.50 m*	*$0.50 m*	*$0.50 m*	*$0.50 m*	*$0.50 m*					
Northern	*Reliability Improvements - Automated Switchgear*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*
Northern	*Cable Replace - Northern*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*	*$1.70 m*
Northern	*Crossarm Replace - Northern*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*	*$2.30 m*
Northern	*Earthing Upgrades - Northern*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*	*$0.11 m*
Northern	*Ground Mounted Switchgear Replace - Northern*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*	*$0.25 m*
Northern	*Pillar and Pit Replace - Northern*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*
Northern	*Pole Mounted Switchgear Replace - Northern*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*	*$0.33 m*

Region	**Project**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Northern	*Pole Replace - Northern*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*	*$1.75 m*
Northern	*Reconductoring - Northern*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*	*$0.40 m*
Northern	*Transformer Replace - Northern*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*	*$1.55 m*
Northern	*Connector Replacement*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*	*$0.20 m*
Northern	*11kV Indoor Switchboard Replace - English Electric 1954 (10 Panels)*			*$1.80 m*							
Northern	*11kV Indoor Switchboard Replace - Southwales 1963 (11-panels)*		*$2.20 m*								
Northern	*11kV Indoor Switchboard Replace - Southwales 1954 (11 Panels) station rebuild*			*$2.30 m*							
Northern	*11kV Indoor Switchboard Replace - Southwales 1967 - 5 Panels*				*$1.00 m*						
Northern	*11kV Indoor Switchboard Replace - Southwales 1967 - 5 Panels*				*$1.00 m*						
Northern	*11kV Indoor Switchboard Replace - Southwales 1969 - 11 Panels*					*$1.10 m*					
Northern	*11kV Indoor Switchboard Replace - Southwales 1975 - 11 Panels*							*$1.20 m*			
Northern	*11kV Indoor Switchboard Replace - Southwales 1975- 5 Panels*									*$1.00 m*	
Northern	*11kV Indoor Switchboard Replace - Southwales 1976- 10 Panels*									*$1.20 m*	
Northern	*11kV Indoor Switchboard Replace - Southwales 1979 - 11 Panels*						*$1.20 m*				

Region	*Project*	*2011/12*	*2012/13*	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*2019/20*	*2020/21*
Northern	*11kV Indoor Switchboard Replace -Southwales 1967 - 12 Panels*		*$1.30 m*								
Northern	*11kV Indoor Switchboard Reyrolle (10 Panels)Retrofit*			*$0.50 m*							
Northern	*11kV Indoor Switchboard Reyrolle (11 panels) Retrofit*		*$0.55 m*								
Northern	*11kV Indoor Switchboard Reyrolle (12 Panels) Retrofit*				*$0.60 m*						
Northern	*11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit*						*$0.25 m*				
Northern	*11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit*							*$0.25 m*			
Northern	*11kV Indoor Switchboard Reyrolle (5 Panels) Retrofit*							*$0.25 m*			
Northern	*11kV Indoor Switchboard Reyrolle (6 Panels) Retrofit*								*$0.30 m*		
Northern	*11kV Indoor Switchboard Reyrolle (7 Panels) Retrofit*					*$0.35 m*					
Northern	*11kV Indoor Switchboard Reyrolle (7 Panels) Retrofit*						*$0.35 m*				
Northern	*11kV Indoor Switchboard Reyrolle (9 panels) Retrofit*										
Northern	*11kV Indoor Switchboard Reyrolle (LMT 6 Panels)- Station Rebuild*		*$3.00 m*								
Northern	*33kV Indoor Switchboard Renewal - Wairau Valley*	*$7.00 m*	*$0.70 m*								
Northern	*33kV Outdoor CB Replace - (2x Reyrolle ORT2)*		*$0.50 m*								
Northern	*33kV Outdoor CB replace (2 x Reyrolle ORT2)*			*$0.50 m*							
Northern	*33kV Outdoor Circuit Breaker*								*$0.50 m*		

Region	Project	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
	Replace (2x Takaoka)										
Northern	*33kV Outdoor Circuit Breaker Replace (3 x Nissin KOR)*							*$0.75 m*			
Northern	*33kV Outdoor Circuit Breaker Replace 1x Eng.E OKW3*						*$0.25 m*				
Northern	*33kV Outdoor Circuit Breaker Replace 1x Eng.E OKW3*		*$0.25 m*								
Northern	*33kV Outdoor Circuit Breaker Replace 1x Eng.E. OKW3*				*$0.25 m*						
Northern	*33kV Outdoor Circuit Breaker Replace 2x Eng.E. OKW3*	*$0.50 m*									
Northern	*Outdoor Circuit Breaker Replace*							*$2.00 m*	*$1.50 m*	*$1.50 m*	*$1.50 m*
Northern	*Power Transformer Replace - Triangle 33*							*$4.00 m*			
Northern	*Power Transformer Replace - Waimauku 33*								*$2.50 m*		
Northern	*Zone Substation Oil Containment - Northern*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$0.30 m*	*$0.30 m*	*$0.30 m*	*$0.30 m*	*$0.30 m*	*$0.30 m*	*$0.30 m*
Northern	*Zone Substatation Seizmic Compl (Ackl&NorthNtwrk)*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*	*$1.00 m*
Northern	*Mushroom Pillars (Risk Register)*	*$0.60 m*	*$0.60 m*								
Northern	*Strategic Spares - Northern*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*	*$0.05 m*
Northern	*Oil-filled Distribution SwitchGear –Replace/Repair (AIAE3003)*	*$0.50 m*	*$0.50 m*	*$0.50 m*	*$0.50 m*	*$0.50 m*					
Northern	*Carry Over From 2010/11*	*$0.15 m*									

Table 6-33 : 10 years programme of renewal works

Electricity
Asset Management Plan
2011 – 2021

Systems and Processes – Section 7

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

7. Systems, Processes and Data

7.1 Asset information management background

This section describes the information systems and associated business processes Vector maintains and operates to manage its asset data.

Vector's day-to-day operation involves teams undertaking a wide variety of business functions such as maintenance management, asset inspections, asset valuation, financial forecasting, condition monitoring etc.

Many of the key business functions are supported by the same data, systems and business processes. The following diagram (Figure 7-1) is an example of the key information management components and their relationships.

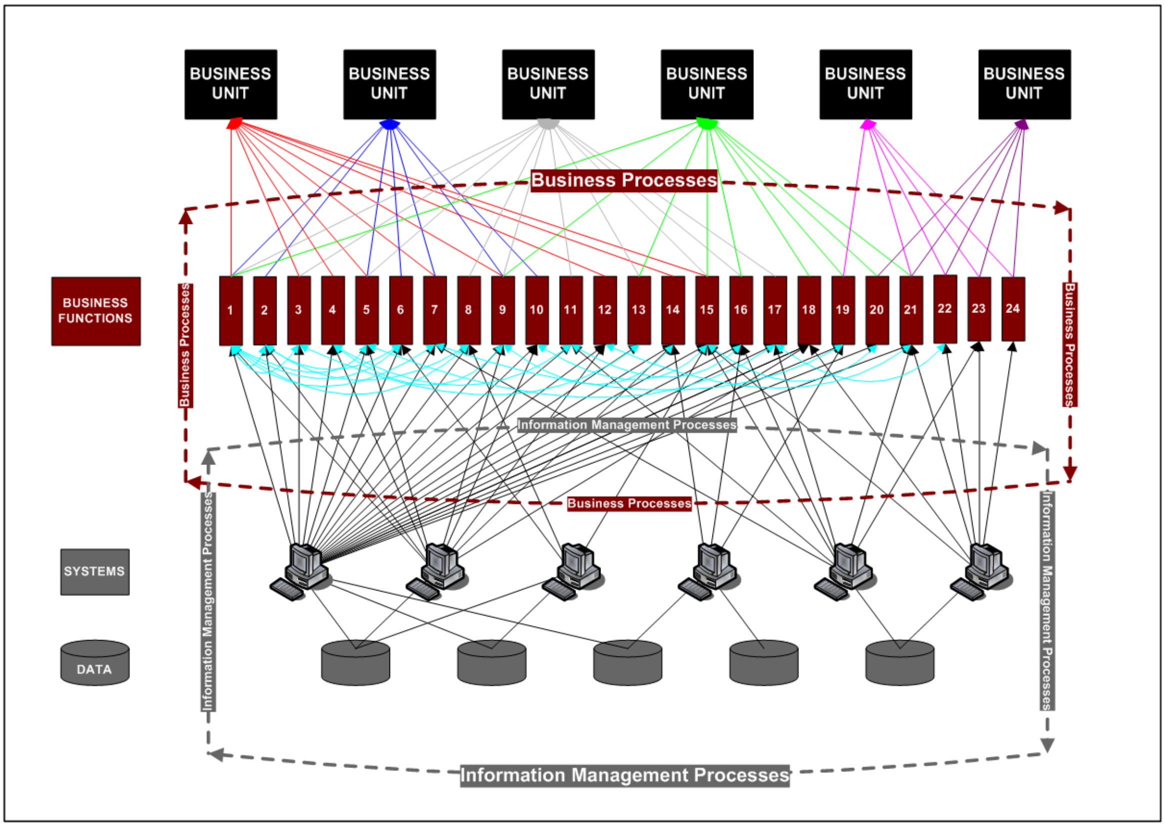


Figure 7-1 : Information Management Framework

Note that while Vector is responsible for asset management, Vector's Field Services Providers (FSPs) are responsible for maintaining the assets and scheduling activities and resources accordingly and use proprietary works management systems for this purpose.

Figure 7-2 illustrates the information flows between Vector and its FSPs by system and activity type.

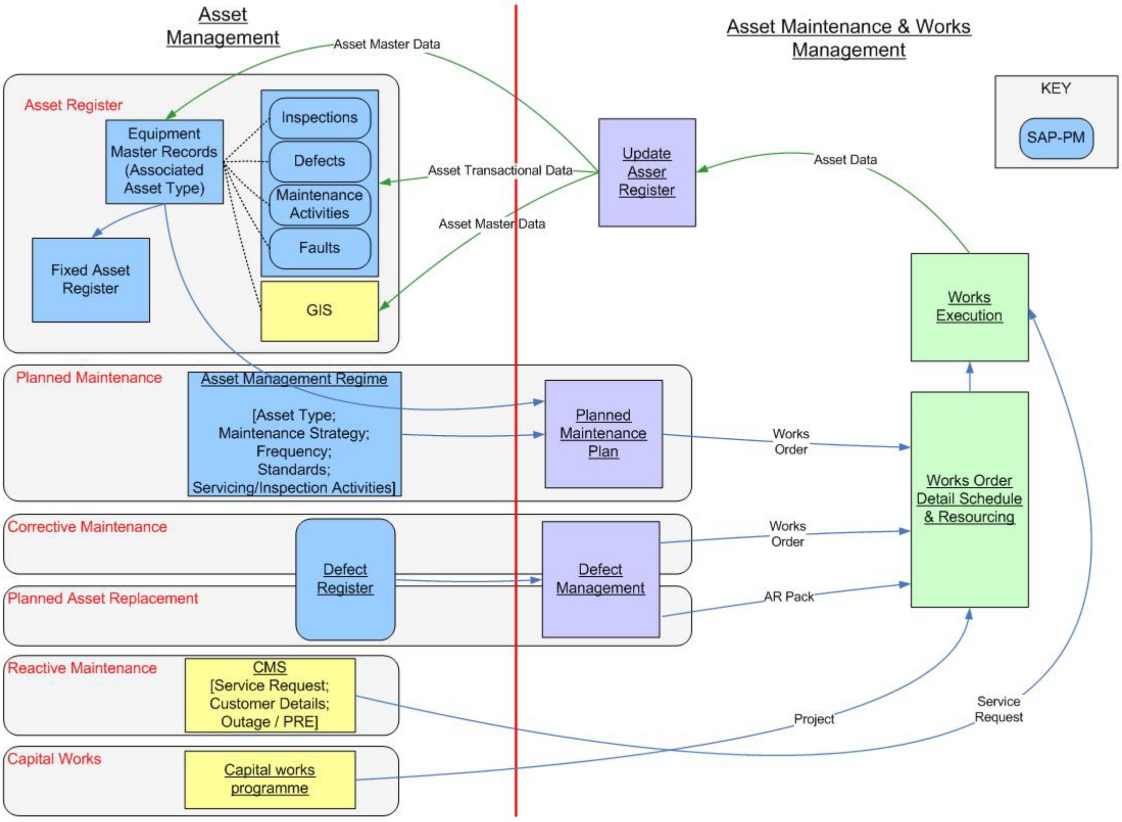


Figure 7-2 : Asset information flows between Vector and its FSPs

Vector has developed a Technical Asset Master (TAM) register in its Enterprise Resource Planning (ERP) system, SAP, which was deployed to the FSPs late in 2010. This was part of an initiative supporting the AI group's strategic goal of improving asset information and data quality across the business, as described in Section 1.11.

The overall structure of the TAM register is shown in

Figure 7-3, and is described in more detail in Section 7.3.1. A key feature of the systems is the degree of integration, made possible by leveraging the capabilities of Vector's ERP system. In addition, an interface to Vector's Geographic Information System (GIS) and linkages with Vector's Customer Management System (CMS) and the FSP's data collection and works management systems.

The TAM register has enabled a range of benefits:

- Better access to asset static and transactional data;
- Improved regulatory and audit compliance;
- Improved ability to reconcile technical and financial asset registers;
- Improved development, operational and maintenance planning efficiency and effectiveness;
- Improved investment decisions (optimised operational/capital expenditure);
- More accurate network asset valuation;
- More efficient asset creation process (earlier settlement of work in progress);
- Ability to create technical asset records via the procurement process; and
- Improved oversight of works management.

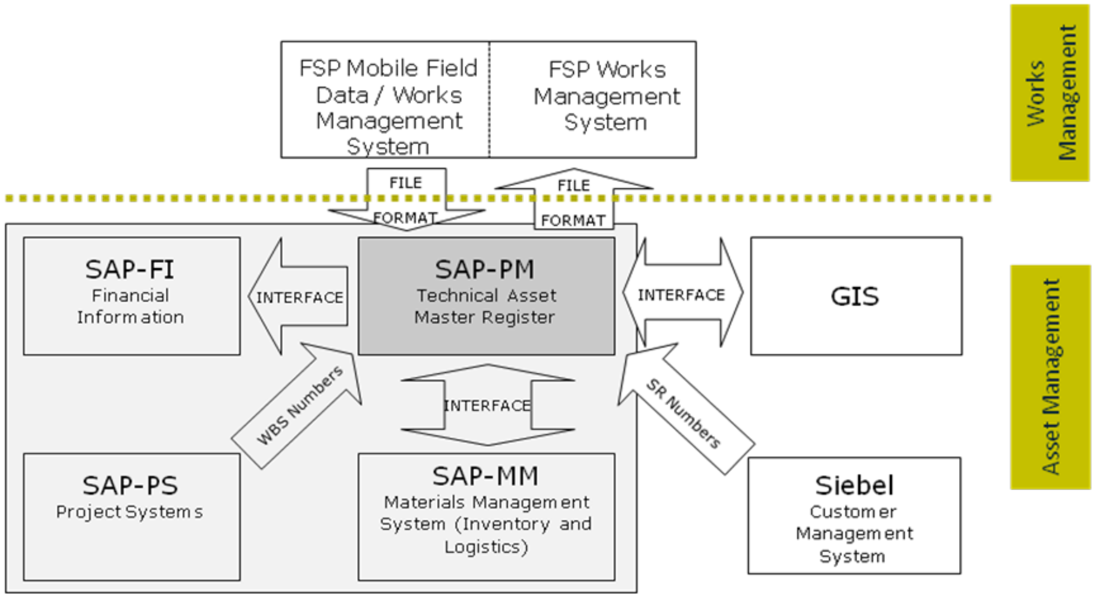


Figure 7-3 : TAM asset management / works management systems

Vector, in common with other providers of integrated infrastructure solutions, is by its nature complex and has, over time, acquired additional layers of complexity in the way its systems, processes and data is structured and managed. However, in line with Vector's group goals of operational excellence, cost efficiency and customer and regulatory outcomes (Section 1.3), it is increasingly important for Vector to adopt a more unified approach to managing asset information.

The TAM initiative represents a significant step to this end, specifically regarding the management of asset lifecycle information. This represents one part of a series of initiatives that has been developed and implemented with the following overall objectives.

Focus	**Objectives**
Asset data	• Reducing the amount of disparate datasets, particularly those in stand-alone systems; • Ensuring all data is fit for purpose in terms of its ownership, definition, quality, completeness, accuracy, security and sourcing; • Continuing to cleanse data through a prioritised programme of improvement initiatives; and • Achieving full connectivity (allowing tracing from customer to supply).
Business processes	• Developing mature, consistent and repeatable business processes with the objective of simplifying the end-to-end management of asset information; • Ensuring ownership and quality assurance by closing the "information loop"; and • Attending to issues of communication within and between business

Focus	Objectives
	units in order to avoid duplication of effort.
Information systems	• Extracting the maximum value from information systems; • Developing improved and simplified means of transforming data into information; • Delivering integrated solutions, and developing simple user interfaces; and • Marking targeted improvements to address “band-aids” and “work-arounds”.

Table 7-1 : Asset information objectives

7.2 Asset Data Quality

Central to Vector’s approach is the establishment of the TAM as a single master register for all asset static data (technical asset attributes including hierarchical, spatial and contextual data) and transactional data (inspection, maintenance and defects history), and GIS as the master for geospatial data and connectivity.

A separate master repository is maintained for historical time-series data derived from numerical relays and other Intelligent Electronic Devices (IEDs). In addition, Vector employs specialised tools for network modelling, network monitoring and control, and the management of engineering drawings and documents.

Table 7-2 following summarises changes made to address data quality in the last year.

Data Set	Prior Practice	Current Practice	Implemented
Asset identification	Unique ID numbers in GIS for all geospatial assets and Fixed Asset Register (FAR) for all significant assets	Unique ID numbers in GIS and Technical Asset Register (TAM) for all assets	2010
Asset classification	Hierarchical network asset structure in place (in GIS) Financial asset classification for depreciation purposes (in FAR)	1:1 relationship between GIS and TAM and clearly defined relationship between TAM and FAR	2010
Asset serial number	Recorded in GIS	Recorded in TAM	2010
Asset technical attributes	Attributes recorded in GIS, project files and FAR	Master data for all key asset attributes established in TAM	2010
Asset geospatial coordinates	Coordinates recorded in GIS	Coordinates recorded in GIS and also available in TAM	2010
Asset financial data	Recorded in FAR, linked to GIS ID	Recorded in FAR, linked to TAM ID	2010

Data Set	Prior Practice	Current Practice	Implemented
Asset valuation	Derived from data in FAR and GIS	Derived from data in FAR and TAM	2010
Historical asset performance, inspection and maintenance data	Recorded in Vector's FSPs' maintenance management systems	Critical data fields recorded in TAM	2010
Past and predicted future asset lifecycle costs	Derived from MIS and network modelling	Derived from TAM and network modelling	Planned for 2011
Network connectivity	In network diagrams	Network model linked to GIS	Planned for 2011
Network reliability information	Some faults data recorded in GIS but not linked to assets; HV faults recorded in bespoke database	Faults data analysable at the asset level via TAM; HV faults recorded in bespoke database.	Planned for 2011
Network security information	Derived from network model	Derived from enhanced network model	Planned for 2011

Table 7-2 : Improvements to data quality implemented in 2010

Current data quality and security limitations for asset data sets have been quantified by assessment in terms of the current condition (in quality and security terms) and criticality of the data (defined in terms of sensitivity and availability). A series of initiatives is in train to address these limitations, as described in Section 7.4.

7.3 Asset Information Systems

7.3.1 Technical Asset Master

The TAM register, implemented in SAP-PM (Plant Maintenance) provides a complete inventory of all network physical assets, including strategic spares, and is the master record of all static information (attributes or characteristics) about Vector's network physical assets, with the exception of geospatial information and connectivity.

As shown in

Figure 7-3, SAP-PM has been interfaced with Vector's GIS; SAP internal linkages have been configured with SAP-MM (Materials Management) to facilitate efficient processes for asset creation, installation, refurbishment and disposal; and with the financial fixed assets register in SAP-FI (Financial Information).

In line with the objective of optimising our lifecycle asset management capability, the SAP-PM system and associated business processes have been designed to hold the planned maintenance regime for each asset, according to the relevant engineering standard, and to capture transactional information against each asset record, including inspection activities, maintenance activities and defects.

The TAM is continually updated by asset data specialists within Vector's FSPs through an as-building process in which static (attribute) data is captured in SAP-PM and partially transferred to GIS and geospatial data is captured in GIS and transferred back to SAP-PM.

7.3.2 Customer Management System (CMS)

Vector uses Oracle's Siebel application for its CMS. A full record of network faults is captured by Vector's FSPs in Siebel. This includes certain asset-related technical information as well as the operational and customer information more conventionally associated with CMSs. In order to enable reporting and analysis of this information from an asset management perspective, whenever a specific asset is associated with a network fault event, the asset record in SAP-PM includes reference to the corresponding CMS service request (SR) number.

7.3.3 Geographic Information System (GIS)

A geospatial model of Vector's electricity network between the Transpower GXPs and the customer connection interfaces is maintained in a proprietary database mapped into Smallworld GIS. The model is continually updated by the asset data specialists within Vector's FSPs as described above. GIS acts as the master register for asset geospatial information and default network connectivity.

Analysis and thematic mapping of the information in Vector's GIS is facilitated by exporting base data into ArcGIS and is made accessible to third parties as a reference for underground service locations, and for other purposes including the coordination of works within Vector and externally.

7.3.4 Fixed Asset Register (FAR)

We maintain a register of our financial FAR in SAP-FI (Financial Information). The FAR provides the basis for depreciation, taxation, valuation and financial reporting, and is currently reconciled on a monthly basis with TAM data. The FAR is continuously updated by the master data held in the TAM.

7.3.5 Asset Data Reporting

Reports are created out of each of the SAP modules (PM, MM and FI) and GIS. Additionally, Vector uses SAP-BW (Business Warehouse) and other professional reporting tools including information visualisation, including spatial mapping, to facilitate holistic reporting and analysis of asset management data, including that held in other systems, for example CMS.

7.3.6 Asset Classification Data Flows

In order to support consistency between the component parts of Vector's asset management system, classification data is strictly controlled and maintained as shown in Figure 7-4.

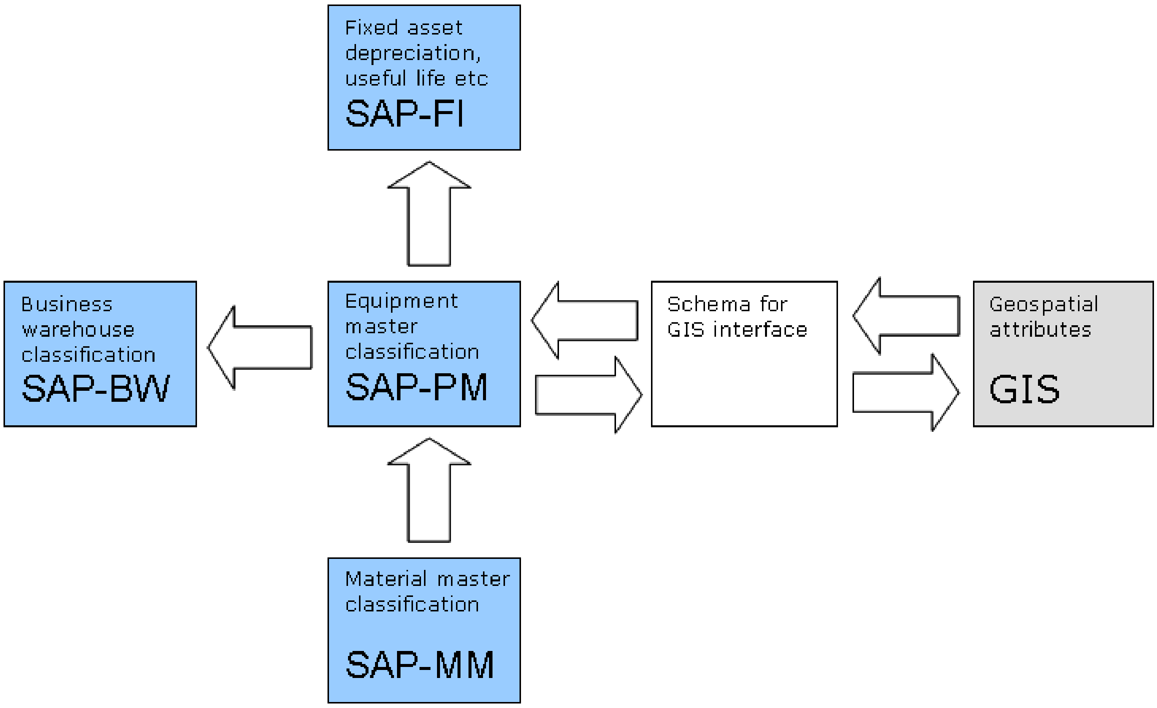


Figure 7-4 : Asset classification data flows

7.3.7 Network Valuation Model

Vector's network asset valuation for financial reporting purposes and Commerce Commission disclosure purposes is derived from the asset data maintained in the FAR, TAM and GIS.

7.3.8 Time-Series Data

A very large archive database of historical time-series data is maintained in an OPC (Object linking and embedding for Process Control) formatted repository, PI, which captures data transmitted across the SCADA system from several hundred IEDs located at zone substations and other key points around the electricity network. This information is used to provide asset utilisation information and support decision-making in network planning and operational control.

In line with Vector's policy to adopt best practice industry standards, we have adopted a standardised convention for a topological data model in accordance with the electric power system Common Information Model (CIM) defined by IEC61970-301. This allows easy alignment with the IEC61850 standard for the exchange of time-series and real-time data between IEDs and systems, including SCADA and PI.

The PI system was upgraded recently to enable advanced calculations to be performed practically in real-time, and transmittal of notifications to FSPs and others, either directly, or via SAP-PM. In due course, by combining time-series data with the TAM data in SAP-PM, Vector's ability to execute condition-based/risk-based asset maintenance strategies will be enhanced.

7.3.9 Network Events Log

A replica of Vector's high voltage and medium voltage network structure is maintained in a bespoke system, HV Events, to manage the recording of interruption events and to prioritise network reconfiguration and restoration after an event.

The number of customers affected and the duration of interruptions to be identified against each event, by event type and location is enabled by logging events at the individual distribution transformer level.

Reporting of network reliability and calculation of asset performance statistics is derived from the data captured in this system.

Network performance is monitored through ongoing review of the data captured in HV Events by the Network Performance team comprising representatives from Asset Investment, Customer Services and Network Operations. Significant equipment-related incidents are cross-checked with the relevant asset engineer in order to identify root causes of incidents and put in place immediate and permanent corrective actions as appropriate. Results are currently logged in a stand-alone faulted-equipment database.

7.3.10 Network Modelling Software

Vector's high voltage and medium voltage electricity networks are modelled with DIgSILENT PowerFactory software. Vector also operates the StationWare application for the management of its system protection settings. This enables Vector to undertake a wide range of power systems studies on the network in its present state and to model the potential impact of changes to the network configuration or to the network load.

The model has been upgraded in line with IEC61850 and Vector's technical requirements for protection and control, in order to support enhanced reliability and security analysis.

A major current development involves the programmatic updating of PowerFactory via importing from GIS.

7.3.11 Network Monitoring and Control

Vector's electricity network is monitored and controlled in real time using the SCADA system (refer to Sections 5 and 6 for a more detailed description).

7.3.12 Customer Connections

Vector maintains a database of all Installation Control Points (ICPs) in the Gentrack system, which is linked to its GIS and Interruption Events systems and the Metering and Reconciliation Industry Agreement (MARIA) electricity industry connections register.

7.3.13 Technical Document Management

Vector network standards and technical specifications have been developed for design, construction, operation and maintenance of the network, and are the subject of continuous improvement.

Key documents are accessible via Vector's intranet. Engineering drawings and related technical documents from network projects are maintained in a proprietary document management system.

7.4 Improvement initiatives

A 10-year roadmap for asset information systems is being developed that covers three main areas:

7.4.1 GIS

- Use of GIS for design work, which is generally done in CAD (computer aided drawing system), imported into the GIS and then redrawn;
- Addressing data extraction issues (for example, connectivity);
- Eliminating excessive customisation GIS, in order to simplify maintenance and reduce the cost and complexity of upgrades;
- Review of the data model;
- Exploiting the full functionality of the system; and
- GIS system upgrade or platform change.

7.4.2 Technical Asset Master (TAM) register

- As Vector is a utility company managing a $2 billion+ asset, having an effective asset management system is essential. Therefore TAM register is an essential system and its functionality requirements need to be considerably extended via subsequent phases;
- Exploiting current developments by SAP on the handling of linear assets; and
- Improving the usability of TAM for infrequent users, for example through the development of a Graphical User Interface (GUI).

7.4.3 SCADA

- Real time systems need to be further consolidated, in particular, the relationships between SCADA and GIS/network modelling/asset management and reporting systems need to be defined and developed in order to exploit the maximum potential functionality such as condition-based maintenance;
- Operational representation of connectivity needs to be further developed;
- The scope of SCADA needs to be extended e.g. is also being utilised for real-time power systems analysis, outage management, etc;
- The recording of faults against customers and not assets presents considerable problems with respect to equipment performance analysis; and
- The use of HV hardcopy in the Control Room is being phased out.

7.4.4 System Integration

Other than the TAM register, there is limited integration between Vector's information systems. Any linkages tend to be in a standard point to point fashion. The downside of this is when either a new system is added, or an existing system is upgraded, it needs to be re-integrated. There are three core asset information environments within a utility company. These are outlined in Figure 7-5 below; Vector's approach is to develop integrated solutions at all four levels, rather than simply at the application level.

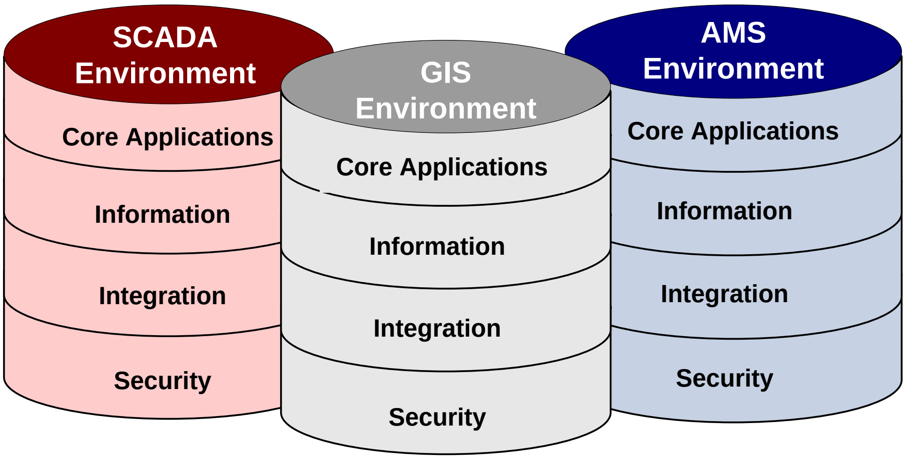


Figure 7-5 : Core environments

The following diagram in Figure 7-6 represents the "As Is" of Vector's current asset information systems, showing limited degree of systematic integration, largely within and between the TAM register.

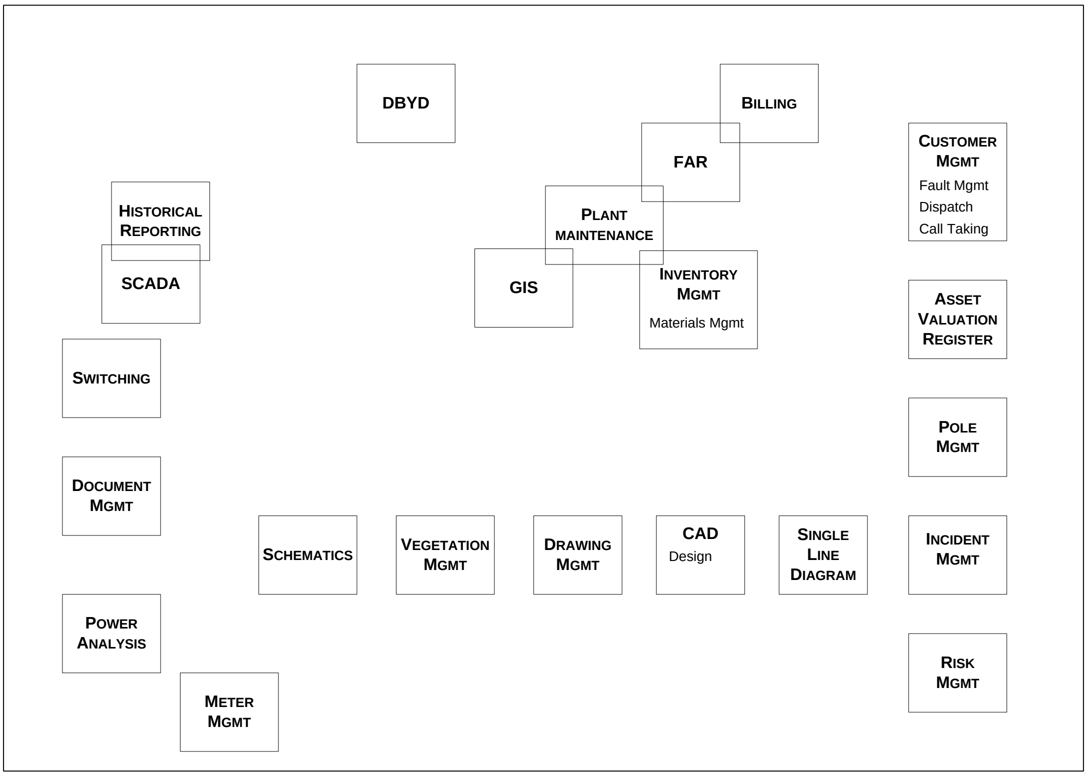


Figure 7-6 : Current state of Vector's asset information systems

Figure 7-7 illustrates the proposed integrated structure for Vector's asset information systems. The systems in blue are systems that Vector does not currently have, but which are being considered for development.

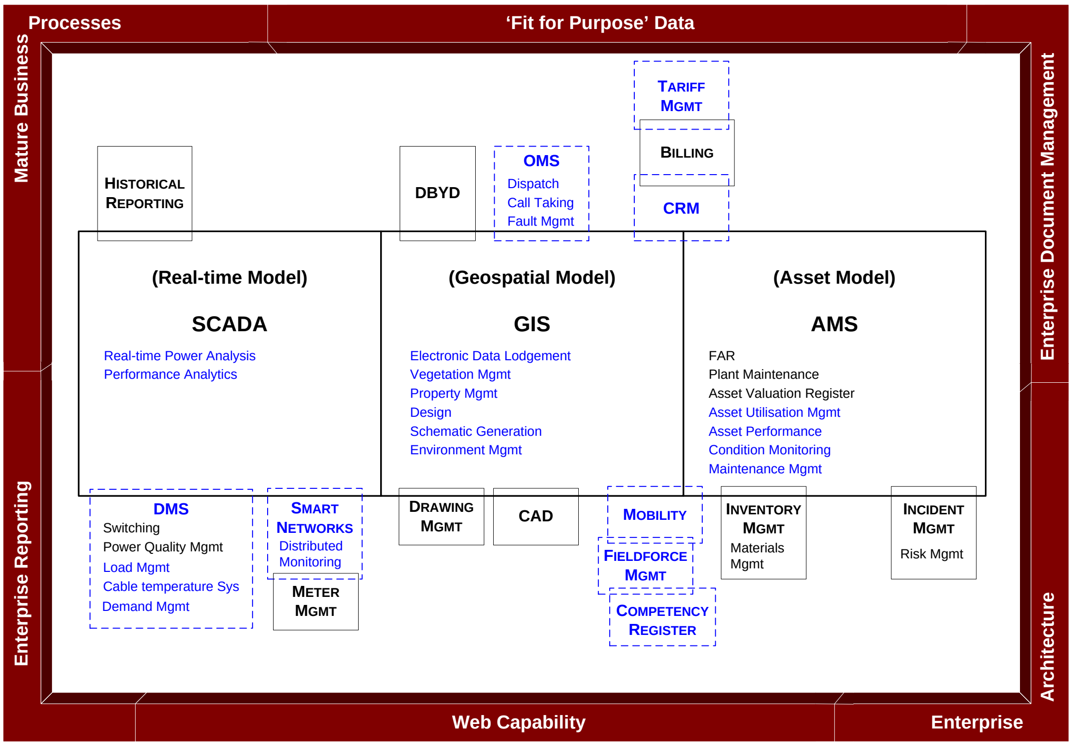


Figure 7-7 : Proposed integrated structure for Vector's asset information systems

7.4.5 Roadmap

Figure 7-8 provides an overview of the proposed strategic direction for Vector's asset information systems.

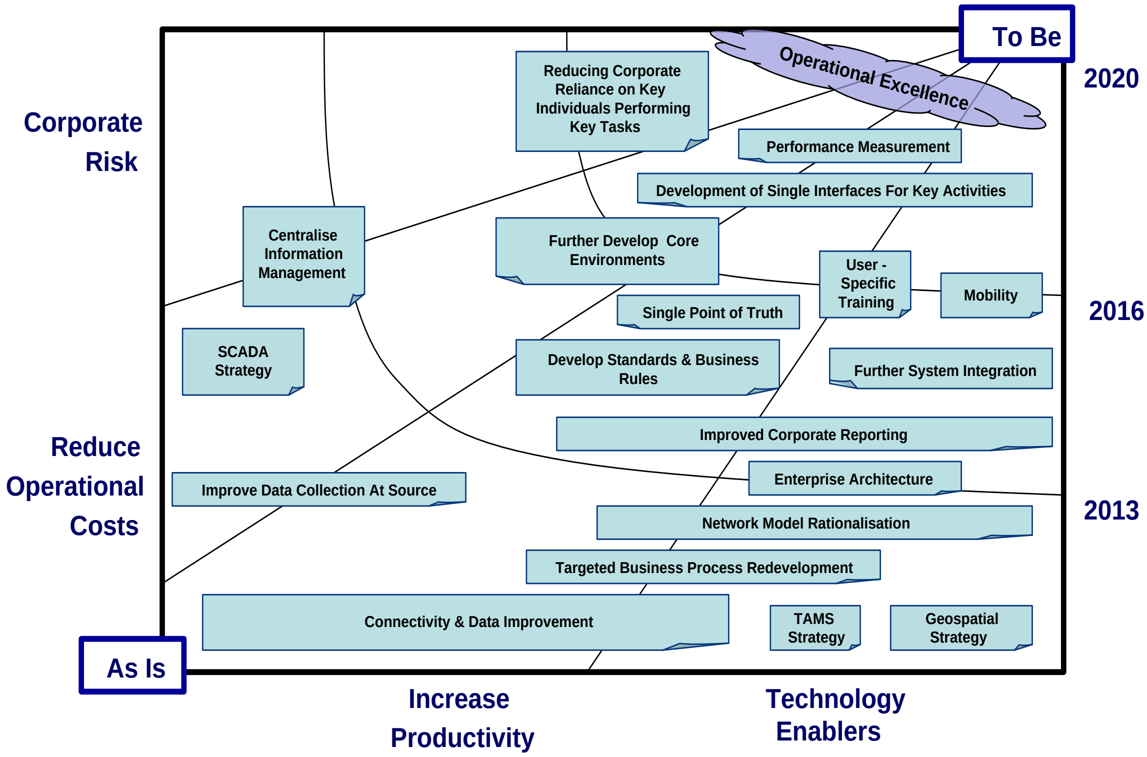


Figure 7-8 : Indicative strategic direction for Vector's asset information systems

Following the completion of the TAM programme to establish an integrated asset management systems platform, Vector has identified GIS and SCADA as priority areas for development and integration.

A geospatial strategy is therefore being developed that considers GIS capabilities, drawing management, DBYD (dial-before-you-dig), online mapping tools, data visualisation and crucially the extent of required system integration. As part of this work, key business functions are being identified and mapped to the current application landscape, high-level requirements analysis is being determined and a geospatial plan developed, including business case.

Subsequent developments, such as the implementation of Outage Management System (OMS) and Distribution Management System (DMS) capabilities will be contingent on the outcomes of the geospatial strategy, SCADA strategy and GIS / SCADA integration.

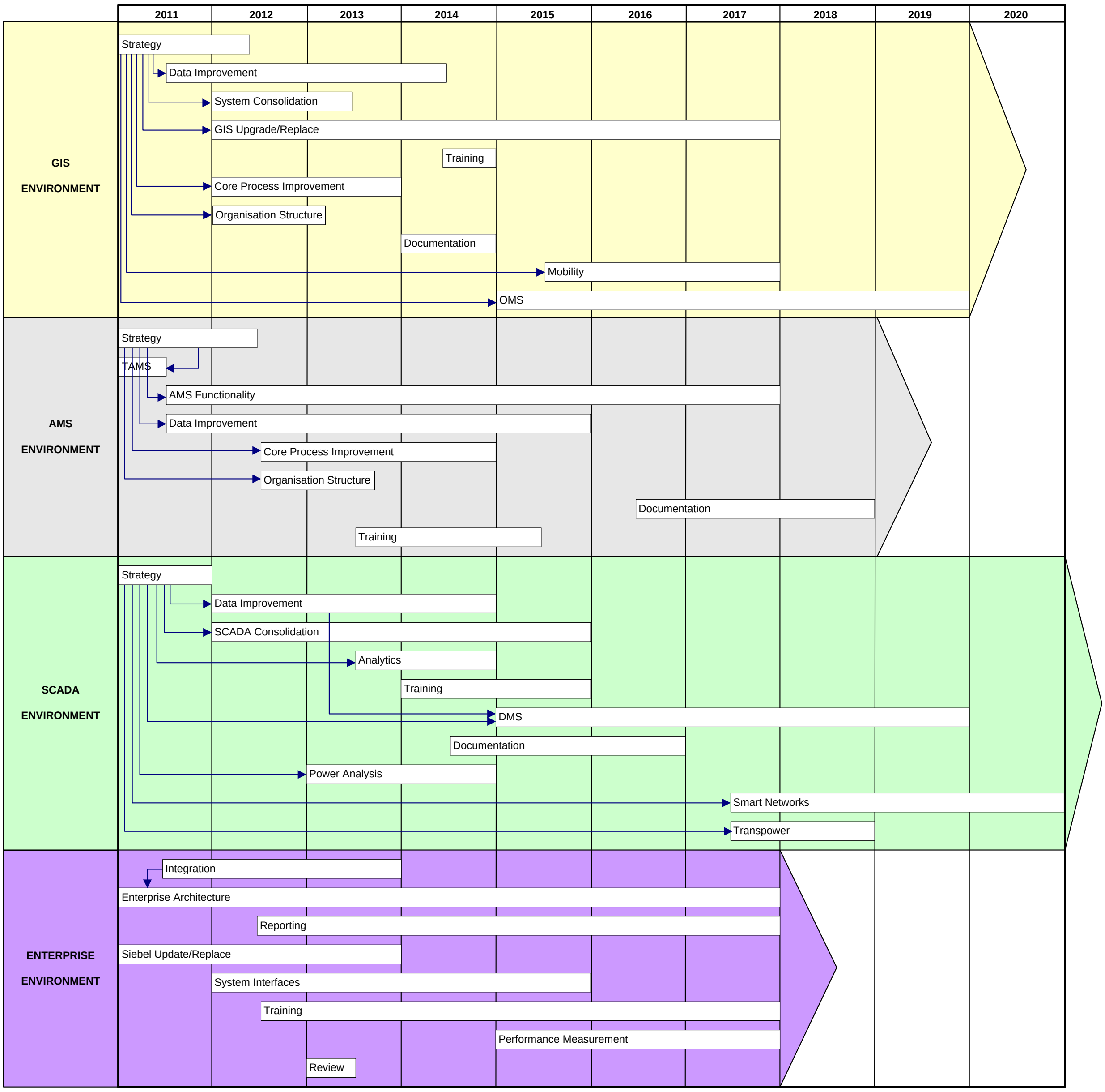


Figure 7-9 : Indicative roadmap for Vector's asset information systems

Electricity
Asset Management Plan
2011 – 2021

Risk Management – Section 8

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

8. Risk Management

8.1 Risk Management Policies

Risk management is integral to Vector's asset management process. Vector's risk management policy sets out the company's intentions and directions with respect to risk management including its objectives and rational. Vector's goal is to maintain robust and innovative risk management practices, consistent with the ISO31000 standard and implement those practices in a manner appropriate for a leading New Zealand publicly-listed company that supplies critical infrastructure and manages potentially hazardous products.

Vector's core operational capabilities, such as asset, operational and investment management, are supported by robust risk management decision-making, processes and culture. Risk and assurance management also underpin Vector's ability to meet its compliance obligations.

The risk management capability is built on a risk management process which requires risks to be identified and analysed. This analysis takes the form of understanding both the nature of a risk and its level. This includes identifying and evaluating any controls in place. A 'control' is any policy, practice or device which is in place to modify (reduce) a risk. With this information risks are evaluated against Vector's risk management framework and a decision made as to whether the level of risk is acceptable. If it is not acceptable a 'treatment' is developed and prioritised against others. In terms of asset management these often become security of supply or asset integrity capital projects, or become the basis for work practice decisions. The effectiveness of the controls and the delivery of these projects are subject to ongoing monitoring. The consequences and likelihood of failure or non-performance of assets, the current controls to manage these, and required actions to mitigate risks, are all documented, understood and evaluated by Vector as part of the asset management process.

The acceptable level of asset-risk will differ depending on the impact, should an asset fail, on the electricity supply or its potential for harm. This in turn is influenced by the different categories of customers, communities' willingness to accept risk and the circumstances and environment in which the risk would occur. Risk analysis covers a range of risks from those that could occur at a relatively high frequency but with low impact, such as tree interference, through to low probability events with high impact, such as the total loss of a zone substation for an extended period.

Risks associated with assets are primarily managed by a combination of:

- Reducing the probability of failure through the capital and maintenance work programme and enhanced work practices; and
- Reducing the impact of failure through the application of appropriate network security standards, robust network design supported by contingency and emergency plans.

8.2 Risk Accountability and Authority

8.2.1 Vector Risk Structure

Figure 8-1 shows Vector's risk management structure and reporting lines.

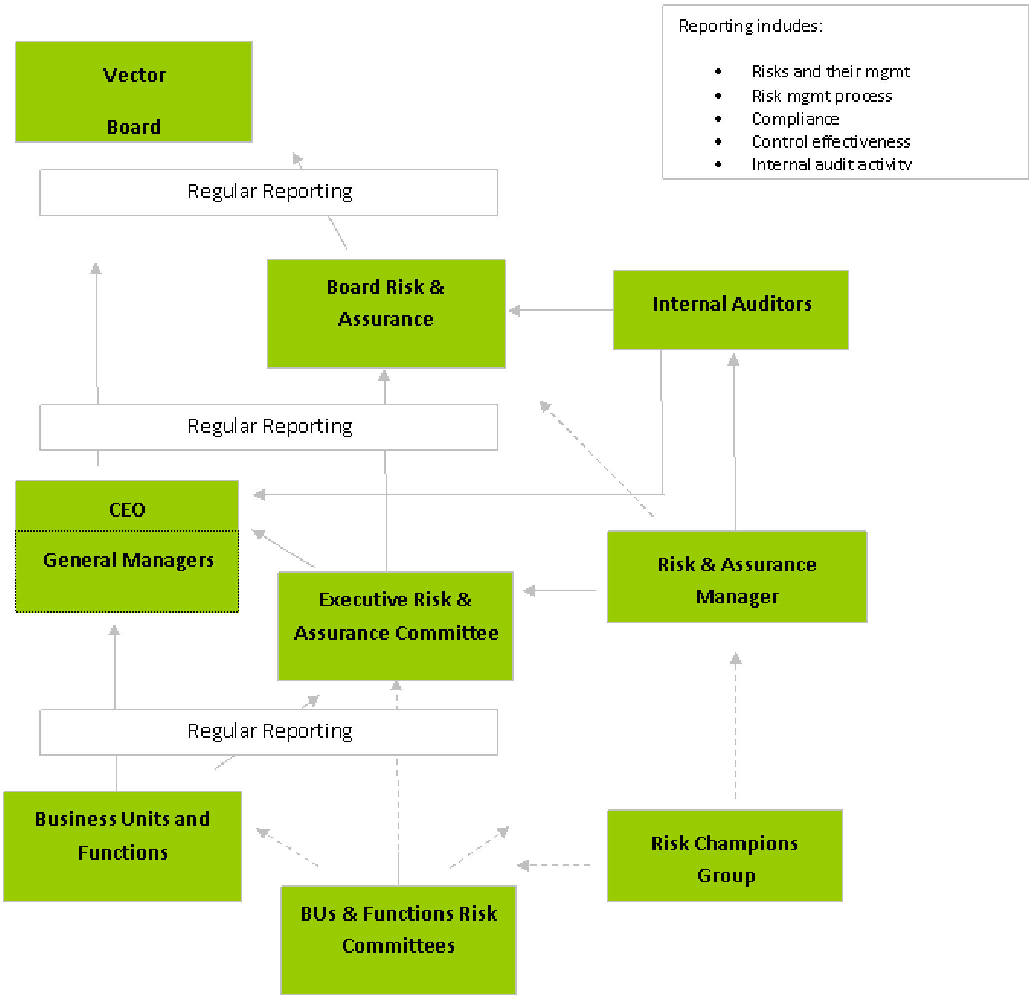


Figure 8-1 : Vector's risk management structure

The following paragraphs describe the accountabilities and authorities of the committees within the risk management structure.

8.2.2 Board Risk and Assurance Committee

Vector's board has overall accountability for risk management. This responsibility (excluding security of supply risks which remain a full board responsibility) has been delegated to the Board Risk and Assurance Committee (BRAC) which provides oversight of Vector's risk and assurance framework and performance.

The BRAC meets at least four times a year to review the group's risk context, key risks and key controls, which include the internal audit and insurance programmes.

8.2.3 Executive Risk and Assurance Committee

The Vector executive has established an Executive Risk and Assurance Committee (ERAC) to provide special specific focus and leadership on risk management. The committee has the overarching responsibility of ensuring risk management and assurance in Vector is appropriate in terms of scope and strategy, as well as implementation and delivery.

The ERAC meets six weekly to review risk management policy and its implementation, as well as key risks.

Vector has also established a Business Continuity Management Steering Committee made up of a mixture of executive and management with specific related responsibility to focus on the development and management of Business Continuity Management (BCM) throughout the company including the operations of electricity networks.

8.2.4 Management and Business Areas

The group general managers and their direct reports have responsibility for ensuring that sustainable risk management and assurance practices are developed and effectively implemented within each of Vector's business groups.

Asset related risks and their control and mitigation measures are largely the responsibility of the Asset Investment (AI) and Service Delivery (SD) groups. The AI group oversees network asset management strategy and performance and includes the development of standards for the electricity network and its component assets.

The SD group manages the operational delivery of the strategy. This includes delivery in the field of the requisite levels of maintenance and capital expenditure (capex) so the network meets the stated reliability, safety, environmental and performance standards. The SD group also manages the safe and reliable operation of the network to predefined levels.

8.2.5 Risk Champions

Risk champions have the responsibility of facilitating risk management practices in their business groups by:

- Ensuring, in conjunction with the risk-owners, that their risk registers are accurate and up to date;
- Completing general risk management reporting requirements within their business groups;
- Ensuring effective risk management meetings are conducted in their areas (and cross-functionally as appropriate); and
- Ensuring appropriate risk communication and induction is undertaken in their business groups.

8.2.6 Risk and Assurance Manager

The Vector Risk and Assurance Manager is responsible for the development of a risk management framework, which includes a risk management plan outlining the approach, management components and resources applied to risk management. The risk management framework is approved by the ERAC.

The role includes the monitoring and reporting of progress against this plan and overall delivery of risk management and assurance across Vector, as well as communicating on risk management and assurance issues across Vector.

8.2.7 Staff

Each staff member is responsible for ensuring they understand the risk management practice in Vector and how it applies to them. This includes being actively engaged in the identification of new risks and ensuring these are appropriately acknowledged.

Individual staff may have specific responsibilities for the ownership and management of a specific risk, control or treatment depending on their roles.

8.3 Risk Management Process and Analysis

8.3.1 Risk Management Process

Vector has adopted the risk management principles and guidelines detailed in AS/NZS ISO31000:2009. This standard was largely based on AS/NZS 4360:2004 which Vector had used in the development of its initial policy and framework. Given the consistencies between the standards there were no major problems with the adoption of the new principles and guidelines.

The risk management process adopted by Vector is shown in Figure 8-2 below.

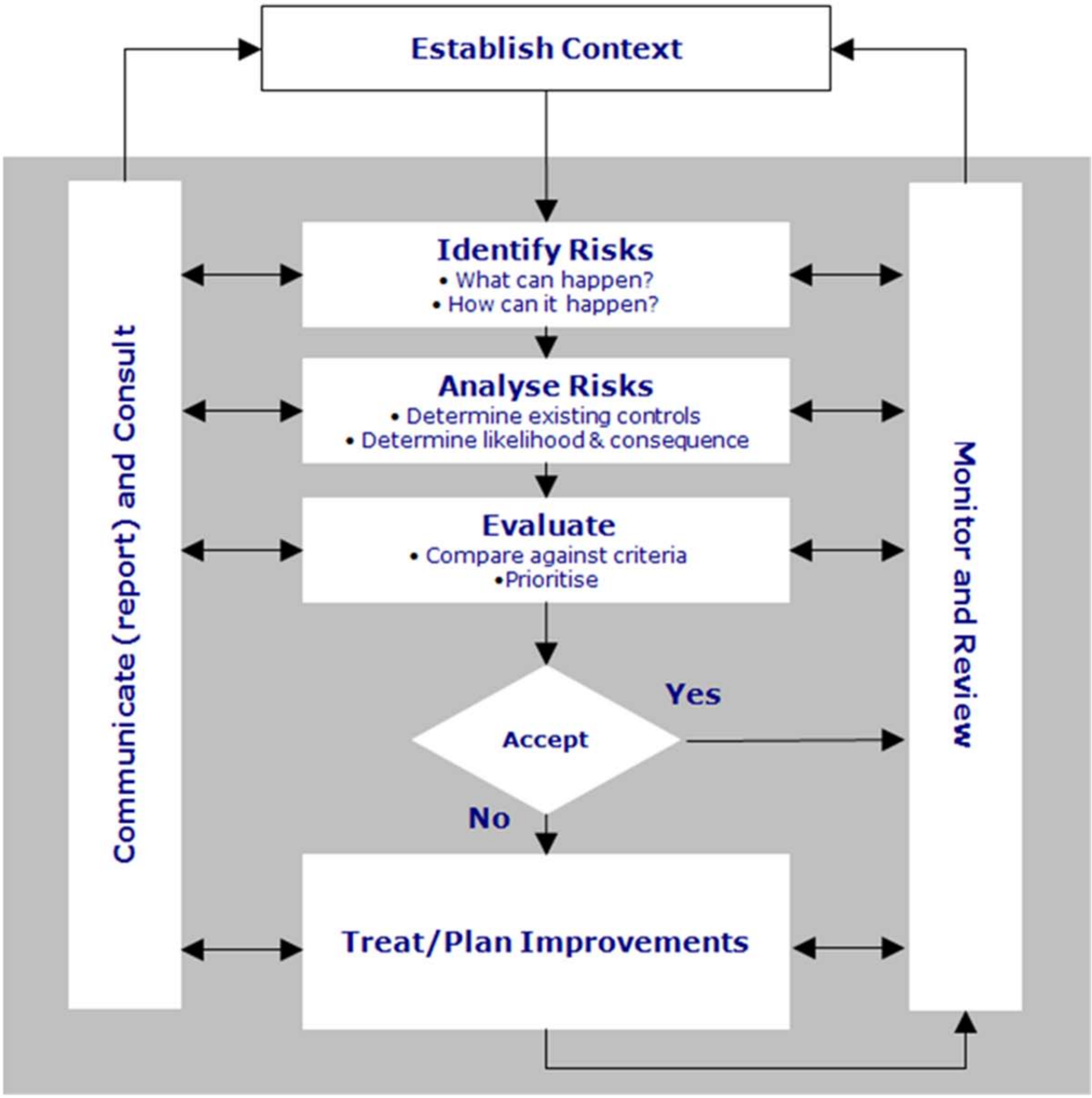


Figure 8-2 : Vector's risk management process (based on ISO31000: 2009)

The level of a risk is determined by considering the combination of the "likelihood" and "consequences" of the risk occurring given current controls. This is then compared to Vector's risk assessment matrix as shown in Figure 8-3 below. The overall risk level is used as a key factor in determining the acceptability of the risk and driving the need and priority of any subsequent action.

Risks which have "catastrophic" or "major" risk consequences include those which could lead to loss of life, cause serious damage to the environment, create a major loss of electricity supply, lead to major financial loss or have a significant impact on Vector's reputation.

Vector has controls in place to manage key risks and has internal review processes associated with these controls. A key component of the assurance process is Vector's internal audit programme which provides assurance around controls, including the organisation-wide governance ones such as 'risk management' and BCM. The Internal Audit programme is overseen by the BRAC.

Figure 8-3 : Vector's risk assessment matrix

The asset management process is also specifically reviewed by an independent third party as a requirement of the AECT Trust Deed which governs key aspects of how the company must operate. The results from this review are reported through to the full board.

8.3.2 Network and Asset Risk Management

The management of the electricity network assets is underpinned by the risk management principles described above. The AI group which oversees network asset management and performance uses these principles in the development of standards for the electricity network and its component assets.

The SD group manages the operational delivery of the strategy. This includes delivery in the field of the requisite levels of maintenance and capital development so the network meets the stated risk rated reliability, safety, environmental and performance standards. The SD group also manages the safe and reliable operation of the network to predefined levels.

The AI and SD groups both have an integrated approach to risk management and their respective responsibilities in relation to it, which encompasses:

- Identifying and assessing risks;
- Managing and maintaining controls;
- Developing and implementing treatments proportionate to the risk involved;
- Monitoring risks, the effectiveness of controls and progress of treatments;
- Maintaining up to date risk registers which clearly identify risks, the ownership of the risks, possible outcomes and mitigation measures; and
- Reporting these risks, controls and treatments to the ERAC and BRAC as appropriate.

Regular risk meetings are held at all levels of Vector, and within the AI and SD groups, at which the existing risk registers are reviewed, potential risk scenarios discussed, and new risks identified for inclusion in the risk registers (along with the appropriate mitigation measures).

8.3.2.1 Risk Registers

Vector's risk registers identify risks and capture their management at different levels of detail and at different levels of responsibility, taking a tiered approach. These are routinely reviewed and reported on.

The risk registers report absolute risk classification (.e. excluding any organisational controls) and the risk classification with controls and treatments in place. The treatments are initiatives which are undertaken primarily to reduce the risk. These risks are managed at various levels, as appropriate, within Vector. The findings are reflected in Vector's asset planning outcomes. The most significant risks have visibility through to the ERAC and to the BRAC.

Table 8-1 below shows the key information requirements for risks in Vector's risk registers.

Heading		Description
Unique ID number		Unique code for each risk
Risk Description	Short name	Short name for the risk to ease communication
	Full name and consequence	Full name defines the event or circumstance and the consequences which emanate from this risk
Categorisation	Strategic impact	One of 5 predefined categories
	Strategic objective	One of 18 predefined categories
Risk tier		Categorises risk in to one of three groupings in terms of breadth verses detail

Heading		Description
Product type	Product type #1	What product in the group the risk is associated with, such as electricity, gas etc
	Product type #2	What - sub product of the above the product risk is associated with, such as for gas - wholesale gas
Risk Ownership	Function / Business Unit	Reporting unit
	Sub function	Reporting sub-unit within reporting unit
	Owner	Name of owner of risk
Absolute	Consequence	Absolute - Consequence. Likely impact with no controls in place
	Probability / Likelihood	Absolute - Probability. Likelihood of risk occurring if no controls were in place
	Risk Assessment	Absolute - Risk Assessment. Assessment of risk as a combination of likelihood and consequence with no controls in place
Controlled	Consequence	Controlled - Consequence. Impact with (effective) controls in place
	Probability / Likelihood	Controlled - Probability. Likelihood of risk occurring with (effective) controls in place
	Risk Assessment	Controlled - Risk Assessment. Assessment of risk as a combination of likelihood and consequence with (effective) controls in place
Treated / 'As Low As Reasonably Practicable' (ALARP)	Consequence	Treated - Consequence. Impact when treatments are completed
	Probability / Likelihood	Treated - Probability. Likelihood of risk occurring when treatments are completed
	Risk Assessment	Treated - Risk Assessment. Assessment of risk as a combination of likelihood and consequence when treatments are completed
Assurance process	Key Controls	A brief description of controls
	Status	An evaluation of the quality of the control
	Process	How we get assurance of the control
	Control review date	When the control gets reviewed
	Control owner	Who manages the control

Heading		Description
Treatments	Treatment name	A brief description of treatment
	% Complete	% of project complete
	Completion date	Date when treatment is scheduled to be complete
	Treatment owner	Owner of treatment
Admin	Risk origin	To track risk origin in terms of any past register / or to note as "new"
	Date listed	Date when risk was added to register
	Reviewer	Name of person who reviewed the risk
	Last updated	Date when risk has last been reviewed

Table 8-1 : Risk register headings

8.3.2.2 Key Operational Risks

Table 8-2 below outlines the most significant electricity risks Vector has identified in its asset management risk profile. While control and mitigation measures are in place to address these, work is ongoing to improve the controls and to ensure they remain effective.

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
AIAE5006	An asset or the way Vector operates the business exposes staff, contactors and/or the public to various forms and levels of risk. If a risk eventuates it could lead to a health concern, injury or death of any one of those parties leading, also to costs, liabilities/penalties and potential regulatory consequences.	Very High	Moderate	Moderate
AIAE5008	Risk from underperformance, breakdown failure of equipment or processes associated with running the networks or plants potentially leading to lost revenue, cost/losses, liability reputational, customer dissatisfaction and potential regulatory outcomes.	Extreme	Moderate	Moderate
AIAE5001	External events such as natural disasters (storms, earthquakes, volcanoes) or man-made related disasters (accidental or sabotage) disrupt the operations, or damage or	Very High	High	High

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
	destroy Vector assets potentially leading to lost revenue, cost/losses, liability, reputation damage, customer dissatisfaction and/or potential regulatory consequences.			
AIAE5002	An asset or the way Vector operates the business exposes the environment to damage in different forms and levels. If a risk eventuates it could potentially lead to damage to the environment, creating a health concern, which in turn could lead to costs, liabilities or regulation/ penalties being incurred.	High	Moderate	Moderate
AIAE1007	Electricity SCADA system failure resulting in reduced visibility and/or control of electricity distribution network inhibiting response in an event.	High	Low	Low
AIAE1014	Electricity SCADA system resilience. An audit of the Vector electricity SCADA environment by Deloittes identified a number of actions that can be undertaken to improve network performance and safety.	Very High	Very High	Moderate
AIAE4024	Security of supply to Wairau Rd substation (110kV). 110kV supply to Wairau Rd substation is dependent on a double circuit 110kV line. Loss of this line would result in significant outages on the network.	Very High	Very High	Low
AIAE1038	Power quality performance below compliance levels. The risk is that Vector is unable to deliver power quality to acceptable standards, which has the potential to lead to a loss of reputation and regulatory consequences.	Very High	High	Moderate
AIAE3017	Risk of tower failure due to corrosion. There are a number of rusted and deteriorated towers on the Northern Network. The failure of a tower could potentially cause bodily harm.	Very High	Moderate	Moderate
AIAE3018	Uninsulated stay wires leading to risk of public injury.	Very High	Low	Low
AIAE3020	Potential failure of certain 33kV heat shrink joints undertaken by jointers 1999 -2000.	High	High	Moderate

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
AIAE3031	Injury caused by asset failure with uncertain ownership or Point of Supply location (including abandoned Telecom poles).	High	Low	Low
AIAE3040	King-bolt corrosion on overhead distribution transformer brackets. Possibility of harm as a result of king-bolt failure due to corrosion causing transformer to fall to the ground.	High	High	Moderate
AIAE4021	Loss of 110kV switchboard at Liverpool substation.	High	High	Low
AIAE4025	Electricity transmission supply security into the Auckland region. Transpower's Annual Planning Report identifies capacity and voltage constraints within the Auckland region. There is a risk to Vector's supply security if Transpower is unable to deliver to their plan or their plan is not aligned with Vectors needs.	Moderate	Moderate	Moderate
AIAE1040	Failure of ripple control plant resulting in the inability to control load which may cause high demand.	High	Moderate	Low
AIAE5013	The risk that appropriate new technologies are not adopted to reduce cost, enhance performance or protect the distribution market space. This leads to lack of competitiveness, loss of reputation, stranding of assets and/or increase in cost.	High	Moderate	Moderate
AIPI0003	Inability to identify network operational issues due to poor / corrupted field data. Robust long term maintenance plans and asset renewal strategies to be continually improved to minimise Vector's risk profile while meeting performance targets at the optimal cycle cost. This has the potential to lead to increases in cost, increased SAIDI, loss of shareholder confidence, poor asset management and decision making, which could have implications on cost, network and asset performance and HS&E.	Very High	High	Moderate
AIPI0004	Inadequate utilisation (load profile) information. High capital and	High	High	Low

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
	operating costs resulting from inability to optimise asset utilisation.			
AIPI0011	Serious breaches of electricity reliability criteria.	Very High	High	Moderate

Table 8-2 : Most significant asset risks identified in the Vector electricity asset risk register

8.3.2.3 Integrated Risk Management – Our Aspiration

Vector continues to look to enhance the integration of the risk management process into its core planning and prioritisation activities. It is recognised many of the risk control or mitigation measures require capital investments, and capital investment is largely driven by risk-associated factors.

Anticipated risks identified in the risk register that can be treated by capital investment are included in the 10 years capital works programme (capital expenditure forecasts). These projects are identified by the risk identification number (from the risk register).

Other residual risks are controlled / mitigated through maintenance programme of works. These projects are part of the corrective or reactive maintenance programme.

Table 8-3 gives a summary of the key risks identified in the risk register (cross reference to the risk ID) and the expenditure programme to control / mitigate these risks.

Risk ID	RISK DESCRIPTION - SHORT	Expenditure Programme
AIAE3026	Electricity distribution critical spares, tools and equipment	• System management and operations expenditure
AIAE3046	Building Code compliance - seismic risk to substations	• Routine and preventive opex • Capital expenditure projects
AIAE3050	Increase in fault level due to Vector's work resulting in potential damage to customers' properties	• Routine and preventive opex
AIAE3031	Possible harm caused by asset failure with uncertain ownership or POS location (including abandoned Telecom poles)	• Routine and preventive opex
AIAE3047	Uncontrolled discharge of oil from oil cables	• Fault and emergency opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3021	Uncontrolled oil spillage at zone substations with inadequate protection leading to environmental damage	• Fault and emergency opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3016	Marine cable failure	• Fault and emergency opex • Refurbishment and renewal opex

Risk ID	RISK DESCRIPTION - SHORT	Expenditure Programme
AIAE3014	Cast metal cable pothead failure causing possible harm	• Fault and emergency opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3015	Unidentified loose neutral connections causing possible harm	• Fault and emergency opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3017	Risk of tower failure due to corrosion	• Fault and emergency opex • Refurbishment and renewal opex
AIAE3049	Possible fatality or serious harm resulting from a failure of a 'letter-box pillar' (meter).	• Fault and emergency opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3018	Uninsulated stay wires leading to risk of public injury	• Refurbishment and renewal opex
AIAE3040	King-bolt corrosion on overhead distribution transformer brackets	• Fault and emergency opex • Refurbishment and renewal opex
AIAE3003	Possible harm resulting from explosion of leaning fused switches in SD oil filled distribution switchgear.	• Routine and preventive opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3042	Leaking Series 1 SD distribution switch gear.	• Routine and preventive opex • Refurbishment and renewal opex • Capital expenditure projects
AIAE3045	Possibility of harm or significant property damage associated with equipment failure at a distribution substation.	• Routine and preventive opex • Refurbishment and renewal opex
AIAE3048	Uncontrolled oil loss from distribution assets.	• Fault and emergency opex • Refurbishment and renewal opex

Table 8-3 : Summary of the key risks identified in the risk register

Vector is looking to increase the standardisation of risk descriptions, assessments, evaluations and the prioritisation of treatments and will investigate enhanced computer-based platforms to aid and in their overall analysis and management.

Vector is also intending to develop an overall risk-performance measurement structure which will be used to measure, track and report over time on the effectiveness of the management of individual risks and the overall risk-management process itself (and specifically asset-related risk management).

Components of this integrated risk-management suite are currently being investigated or tested and it is anticipated to have the full system in place by the end of 2011.

8.3.2.4 Incident Management and Reporting

Vector recognises that the effective and efficient management and reporting of incidents is a major element of the risk management process as it is a significant source of information on risks, both their nature and level, and controls, and their effectiveness. Incident management in particular is seen as a key aspect of Vector's health and safety management policy and objectives. It provides a key mechanism to gain insight into the root cause of incidents and provides a valuable opportunity to learn, improve, and avoid similar events in future. In managing incidents, Vector's priorities are to:

- Stabilise and manage the situation. Depending on the event this includes ensuring the safety of its employees, contractors and members of the public; limiting damage to assets; limiting environmental harm, and preserving operations;
- Notify the appropriate internal staff and external authorities, agencies and organisations of the incident;
- As appropriate, investigate the incident and prepare an incident report that considers all of the contributing factors, identifies the root cause and recommends remedial actions as appropriate;
- Carry out any remedial actions; and
- Close out the incident.

Vector has reviewed its incident reporting processes and has implemented enhancements including ensuring there is greater consistency in weekly reporting across the different businesses within Vector.

A team has been established to identify Vector's needs and the options available to move towards the implementation of a more holistic incident management approach to:

- Build a more consistent, cross-business culture focused on reporting and learning from incidents and improving our business;
- Enhance the linkages with risk management processes and definitions;
- Enable efficient reporting;
- Reduce support costs including maintenance, support, licensing, training, etc; and
- Ensure lessons are shared and leveraged across the business.

8.4 Business Continuity Management

8.4.1 Business Continuity Policies

Vector requires an appropriate level of BCM capability in order to meet:

- Its obligations as the owner of "lifeline" utility businesses; such that it is able to function to the fullest possible extent (even though this may be at a reduced level during and after an emergency);
- Customer expectations that service disruptions will be minimised; and
- Shareholders' expectations in terms of protecting value if a disruptive event occurs.

To deliver this Vector has developed a BCM policy which requires that following a range of possible events, emergencies and crises Vector can:

- Minimise their impact on people, operations, assets and reputation;
- Maintain services to the fullest possible extent; and
- Recover to a business as usual position as quickly as reasonably practicable.

To deliver this Vector has established, and maintains, a robust BCM capability. Critical components are live tested on a regular basis to assess the ability to accommodate physical, business and personnel changes. Sufficient personnel are trained to manage serious situations and cope if key people are unavailable.

Vector extends the requirement to maintain a robust and workable BCM capability to its key business partners and external service providers that are relied upon by Vector to support its operations.

8.4.2 BCM Responsibilities

The overall BCM framework and plan is developed and monitored by the Risk and Assurance Manager. Vector's overall BCM capability and programme activities are overseen by a BCM steering committee. Additional oversight is provided by the BRAC and the ERAC.

The head of each business and functional unit is responsible for maintaining the appropriate BCM capability and compliance requirements for their areas. All employees are responsible for contributing to the maintenance of the BCM capability and to assist with the emergency/crisis response and recovery efforts in a real situation.

8.4.3 Business Continuity Capability

To deliver on its BCM policy Vector, as a whole and within its individual functional and business units, as appropriate:

- Undertakes Business Impact Analysis (BIA) and reviews of key disruptive events and recovery timeframes to determine BCM capability requirements;
- Ensures it has in place the appropriate level of BCM capability to be able to respond when a disruptive event occurs. This capability consists of:
  - People;
  - Plans; and
  - Infrastructure.
- Reviews and updates this capability annually (or as required if material external or internal changes have occurred) and has a full review scheduled on an appropriate timescale;
- Ensures the BCM capability extends to third parties where they are key agents in the delivery of an activity for Vector;
- Requires a BCM associated programme of testing to be planned and delivered; and
- Ensures it has appropriate:
  - BCM communication/awareness processes in place;
  - levels of BCM training; and
  - monitoring and reporting.

8.4.4 Business Continuity Plans

With respect to individual Business Continuity Plans (BCP) Vector's policies require appropriate governance aspects to be in place as well as each plan to have certain components.

With respect to governance each BCP:

- Has an owner. The owner has responsibility for the plan and all aspects of the capability around this plan;
- Is developed by those who are associated with the activity and who are named in the plan;

- Is reviewed annually and fully reviewed within a timeframe appropriate to the associated activity, or when required if significant external or internal changes occur;
- Has a programme for testing the combination of:
    - People;
    - Plan;
    - Infrastructure; and
    - Has an appropriate associated training and communication plan.

With respect to components, each BCP:

- Identifies which individuals/groups are notified of an event, including naming appropriate alternates, and having an appropriate escalation process defined;
- Identifies third parties that are required to support a given activity and identifies planning around their disruption;
- Outlines key activities to be undertaken;
- Provides key information required to make the implementation of the plan achievable; such as:
    - Contact lists (internal and external);
    - Maps/plans/drawings/instructions/flow charts;
    - Criticality information;
    - List of required associated equipment; and
    - Appropriate check lists.
- Has appropriate metadata:
    - Owner;
    - Versions; and
    - Date last reviewed and by whom.

8.4.5 Civil Defence and Emergency Management

Vector is classed as a “lifeline utility” under the Civil Defence and Emergency Management Act 2002 (CDEM) and is required to be “able to function to the fullest possible extent, even if this may be at a reduced level, during and after an emergency”. Vector also is required to have plans regarding how it will function during and after an emergency and to participate in the development of a CDEM strategy and BCPs.

Vector has a number of BCPs in place as well as an overall crisis plan.

Vector participates in CDEM emergency exercises on a regular basis to ensure CDEM protocols are understood as well as to test aspects of Vector emergency and BCP plans.

Vector has in place individual emergency response plans for major events and a National Civil Defence Emergency Management Plan that sits above these plans for use in the event of a declared civil defence emergency.

Vector is a member of the Auckland Engineering Lifelines Group (AELG). Membership in the AELG helps ensure Vector keeps abreast of developments in the CDEM area and that it is fully prepared for emergencies arising from identified threats including volcanic eruption, tsunami, earthquake, tropical cyclones and storms, both in general and in particular as they relate to Auckland where it has its electricity distribution assets.

A key area of focus for the company is to better utilise information from the AELG and from other Lifelines groups around the country into its asset management process.

Vector is also a member of the National Engineering Lifelines Committee and keeps abreast of national issues and initiatives through this forum.

8.4.6 BCM and Emergency Response Plans

Vector has a number of plans to cover emergency situations. These plans are reviewed and updated regularly to ensure they are current. Examples of the plans are:

- Crisis Management Plan;
- Major Incident Plan;
- Switching Plans;
- Storm Response Plan;
- Electricity Operations Centre Emergency Evacuation Plan;
- Emergency Load Shedding Plan;
- Participant Outage Plan;
- Vector Group Emergency Communications Plan;
- Vector Group Pandemic Health Plan;
- Transpower Contingency Plans;
- Call Centre BCP; and
- Spill Response Protocol for transformers, switchgear and fluid-filled cables.

These plans are further described below.

8.4.6.1 Crisis Management Plan

The Crisis Management Plan identifies procedures for a crisis affecting Vector, its customers and/or its employees, contractors and other stakeholders. The plan and procedures outlined in this document identify how Vector will manage the consequences of a crisis. It is designed to establish clear lines of communication and reporting, as well as action guidelines for the Vector group.

While the Crisis Management Plan procedures have been developed to cover a broad set of circumstances, Vector is mindful that every crisis has its own unique set of circumstances, which will require good judgement from Vector employees to be managed ably.

The Crisis Management Plan is not intended to cover operational emergency response requirements, as these are covered by the relevant emergency response plans. The plan is designed to support those plans, better enable staff to fulfil their roles as efficiently and safely as possible, and to ensure the wider public implications of an emergency are identified and addressed.

8.4.6.2 Major Incident Plan

The purpose of the Major Incident Plan is to ensure Vector is prepared for, and responds quickly to, any major incident that occurs or may occur on the electricity network. The plan describes the actions required and the responsibilities of staff during a major incident.

A key component of the plan is the formation of the major incident team. This team includes senior staff whose role it is to oversee the management of potential loss, and restoration, of supply following a significant event. The team is very experienced and undertakes exercises periodically on at least annually.

This plan is currently under review as Vector looks to standardise all its approach to operational incidents across the group and across the various product types it manages.

8.4.6.3 Switching Plans

For all major feeders, the network is designed to allow reconfiguration by switching so supply can be restored through an alternative path if there is a failure or a need to shift load. Distribution switching may be carried out remotely via SCADA at all zone substations and selected distribution sites. Vector has an ongoing programme to increase the number of remotely operated distribution high voltage (HV) switches. This enables faster restoration of the power supply by not having to send field staff to operate switches.

In the event of a supply failure on any feeder, the control room staff undertake network analysis and restore power to as many customers as possible by a combination of remote switch operations from the control room and instructing field staff to manually operate field switches.

The control room also has pre-prepared Contingency Switching Plans for major outages such as complete loss of a zone substation.

There are 210 Contingency Plans for the Auckland region. Generally these relate to events that have a “very high” or “extreme” classification within the risk matrix (see Figure 8-3), which corresponds with the loss of a zone substation or critical sub-transmission feeder. These Contingency Plans are reviewed at least once a year.

8.4.6.4 Storm Response Plan

The purpose of this plan is to ensure Vector is prepared for, and responds to, any storm or potential storm that may impact on the electricity network. The plan ensures Vector’s response is appropriate, effective and undertaken in a planned manner whilst ensuring compliance with industry codes and regulations. The plan describes the actions required and the responsibilities of staff during a storm emergency and focuses on continuously improving systems and communications (internal and external) to benefit customers and electricity retailers.

The plan is structured to ensure the establishment and maintenance of effective communications between all parties involved in the maintenance and restoration of electricity supply, and ensures the preparedness and availability of all required Vector resources during an event.

8.4.6.5 Electricity Operations Centre Emergency Evacuation Plan

The purpose of this plan is to ensure that Vector’s network control centre is prepared for, and responds quickly to, any incident that requires the short, medium or long-term evacuation of the electricity operations centre located at Vector’s head office at 101 Carlton Gore Road, Newmarket, Auckland.

The plan describes actions and responsibilities of staff during an evacuation and focuses on continuously improving systems and communications (internal and external) to ensure the management and operation of the electricity network is maintained.

The Vector network control centre has a fully operational disaster recovery site located at Massey, in west Auckland. Regular evacuation exercises are held to ensure evacuation of the control centre can proceed smoothly and at any time.

8.4.6.6 Emergency Load Shedding Strategy

The purpose of this document is to provide procedures for emergency load shedding when required, as requested by Transpower during a grid emergency, or during planned load shedding for energy shortfall. The document does not cover water heating load shedding for reducing peak loads either for network constraints or reducing transmission (peak demand) charges.

Vector is required, under the Electricity Governance Rules 2003, to provide automatic under frequency load shedding (AUFLS) capabilities in two blocks, each of 16% of the total load at all times to maintain grid security. Load shedding will occur automatically under specified system frequency excursion situations. The load groups are reviewed regularly to ensure the required capability is maintained and the priorities are appropriate.

From time to time, Vector is requested by Transpower, acting in the capacity of system operator, to shed load to avoid cascade tripping of the grid under emergency situations. Vector has assigned load groups to cover such contingencies.

8.4.6.7 Participant Outage Plan

As a result of the Electricity Governance (Security of Supply) Regulations 2008, the Electricity Authority has prepared a Security of Supply Outage Plan (SOSOP). Vector is a specified participant and is required to produce a Participant Outage Plan (POP), as specified in the SOSOP.

Under the regulations, POPs are required to specify the actions that would be taken to reduce the consumption of electricity in order to:

- Reduce electricity consumption when requested by the Electricity Authority;
- Comply with requirements of the Electricity Authority’s SOSOP;
- Comply with Electricity Governance (Security of Supply) Regulations 2008; and
- Supplement the Electricity Authority’s SoSOP.

8.4.6.8 Vector Group Emergency Communications Plan

The Vector Group Emergency Communications Plan has been written to ensure that, in any emergency, crisis or business continuity event affecting Vector, Vector's customers, the affected community and other stakeholders are kept well-informed and up-to-date of:

- The status of the emergency;
- Any actions they can or should take to mitigate the affect or consequences of the emergency; and
- When the situation is expected to be (or is) resolved.

The plan is designed as a template that can be tailored to the management response requirements determined by the particular nature of the emergency, crisis or business continuity event. It is designed to provide a consistent, robust and scalable approach to our communications.

8.4.6.9 Vector Group Pandemic Health Plan

As a lifeline utility the Civil Defence and Emergency Management Act (2002) requires Vector to be able to function to the fullest possible extent during and after an emergency.

The objective of this plan is to manage the impact of a pandemic on Vector's employees and our business to ensure continuation of our network operations through two main strategies including the containment of disease by reducing spread within Vector's offices and facilities, and maintenance of essential services if containment is not possible.

8.4.6.10 Transpower Contingency Plans

The purpose of these plans is to assess the consequences of loss or reduction of supply from Transpower's Grid Exit Points (GXP), and planning around the restoration or partial restoration of supply following a catastrophic failure.

The contingency plans have been prepared by Transpower for loss of supply at each GXP. Depending upon the GXP lost, other Transpower substations may also be affected. For example, loss of the Otahuhu GXP would affect all of Vector network north of Otahuhu. Some Transpower GXPs have more than one busbar so supply lost could be to a single busbar or to a whole substation.

8.4.6.11 Call Centre Business Continuity Plan

The core business of Telnet Services, Vector's call centre provider, relies heavily on various computer and telephony technologies that, by their very nature, have the potential to fail.

The purpose of the Call Centre BCP is to assess the potential risks and planned workarounds for those risks in order that Telnet's core business can continue in the event of any failure or disaster. In addition to the general BCP/DR strategy employed at Telnet, there are a number of specific provisions as part of Telnet's relationship with Vector to provide additional services to ensure the continuity of service around handling of safety critical and emergency calls.

8.4.6.12 Spill Response Protocol for Transformers, Switchgear and Fluid-filled Cables

The purpose of this protocol is to document Vector's expectations in the management of liquid spills from all transformers, switchgear and fluid filled cables (FF cables). The document forms part of Vector's overall environmental management response, but places emphasis on the immediate and specific risk of environmental impact from spills from existing facilities.

8.4.6.13 Critical Spares

A stock of spares is maintained for critical components of the network so that fault repair is not hindered by the lack of availability of required parts. Whenever new equipment is introduced to the network an evaluation is made of the necessary spares required to be retained to support the repair of any equipment failures. Refer to Section 6.4 for further details.

8.5 Insurance

The Treasury function manages the placement of insurance for Vector.

Vector's approach to its insurance programme has been to balance risk and cost and has involved regular review of the financial risk appetite of the group. This translates into a programme whereby Vector seeks cover for low probability, major or catastrophic events, and carries as an operational expense the cost of other events which have a lesser financial impact. With respect to the latter category, risk mitigation activity is undertaken to reduce the likelihood of these events through proactive maintenance programmes and thorough management processes.

8.6 Health and Safety

8.6.1 Health and Safety Policy

Vector's Health and Safety Policy states the company's overarching commitments and requirements for health and safety. Vector conducts its business activities in such a way as to protect the health and safety of employees, contractors, members of the public and visitors in our work environment. The company is committed to continual and progressive improvement in its health and safety performance and ensures it has sufficient, competent resources and effective systems at all levels of the organisation to fulfil this commitment.

Any work conducted on and around Vector's assets by external parties, including our service providers, is also required to be conducted in line with the Vector Health and Safety Policy.

Vector's Health and Safety policy objectives are to:

- Provide a safe and healthy work place for all our people, contractors, the public and visitors;
- Ensure health and safety considerations are part of all business decisions;
- Monitor and continuously improve our health and safety performance;
- Communicate with our people, contractors, customers, and stakeholders on health and safety matters;
- Operate in a manner that minimises health and safety hazards; and
- Encourage safe and healthy lifestyles, both at work and at home.

To achieve this Vector:

- As a minimum, meets all relevant legislation, standards and codes of practice for the management of health and safety;
- Identifies, assesses and controls workplace hazards;
- Accurately reports, records and learns from all incidents and near misses;
- Has established health and safety goals at all levels within Vector, and regularly monitors and reviews the effectiveness of our Health and Safety Management System;
- Consults, supports and encourages participation from our people on issues that have the potential to affect their health and safety;
- Promotes our leaders', employees' and contractors' understanding of the health and safety responsibilities relevant to their roles;
- Provides information and advice on the safe and responsible use of our products and services;

- Suspends activities if safety would be compromised; and
- Takes all practicable steps to ensure our contractors work in line with this policy.

8.6.2 Health and Safety Practices

All Vector employees and contractors working for Vector are responsible for ensuring their own and others' safety by adhering to safe work practices, making appropriate use of plant and equipment (including using protective clothing and equipment) and promptly reporting incidents, near misses and hazards to Vector.

Vector's safe work practices manual defines the essentials necessary to maintain an incident free environment. These practices reflect the basic approach necessary for Vector and our Field Service Providers (FSPs) to identify and eliminate incident causes.

Key elements of our health and safety practices, as they relate to our asset base and asset management, include the following:

- Wherever practicable Vector will eliminate, isolate or minimise hazards or control risks to As Low As Reasonably Practicable (ALARP), so as to ensure the safety and health of personnel, the public, the environment;
- The identification of safety and health hazards and the assessment of their associated risks to ensure they are managed to an acceptable level during their operation or associated activities ;
- Vector practices preventative maintenance strategies to all critical plant and equipment to ensure continued safe, environmentally sound, economic and effective operation. In addition, Vector ensures the reliability of critical safety backup equipment, protective devices and key operating equipment is maintained;
- Safety considerations are incorporated into Vector's design standards and asset selection criteria;
- Appropriate safety equipment is installed, inspected and maintained and staff are competent to identify items in need of repair or replacement;
- All FSPs working for the company are required, as a minimum, to comply with Vector's safe work practices whilst carrying out any work on the network. FSPs are also required to report all employee and third party incidents related to work on the Vector network, together with their investigations and corrective and preventive actions;
- Vector monitors electricity related public safety and employee/contractor safety incidents. These incidents are reviewed monthly to ensure lessons are captured and shared with our FSPs;
- Ongoing public safety awareness communications programmes on electricity are undertaken. These include:
    - o Our "Stay Safe around electricity" schools programme, which was started in 2005. Since conception, more than half of Auckland's primary schools have been visited and over 60,000 children have been through the programme, which is designed to raise children's awareness of the hazards of electricity;
    - o An annual "Switch on to Safety" campaign which targets people who undertake Do It Yourself (DIY) activities around their homes. The campaign encourages people to 'think first' before working or playing near our networks and their service lines. This includes high risk activities such as gardening (digging), fencing, tree trimming, painting, water blasting and boating (boat masts and lines hazards, and submarine cables). The

campaign is run over the spring/summer months when these activities are most prevalent. A variety of integrated and targeted media is used - including newspaper (the NZ Herald), internet, email and radio – to deliver the key messages;

- o Promoting safe work practices extensively to external contractors whose work brings them in close proximity to our networks i.e. council and water service contractors, arborists. As well as protecting the contractors themselves, the programme aims to protect the community from hazards and ensure an ongoing safe and reliable power supply to our customers. We provide free services and resources to help contractors work safely around our networks, including free network maps, on-site mark outs and supervision, safety guides and presentations. To ensure it is easy to get in touch with us we have dedicated freephone numbers;
- o Vector is also a founding member of the "before-u-dig service" (www.beforeudig.co.nz). "Before-u-dig" enables contactors to obtain plans from a number of asset owners like Vector, simply by making one enquiry, rather than calling each asset owner individually; and
- o On a regular basis Vector holds a National Safety Day, involving all of its staff, management and strategic contractors. The Vector Safety Day is a visible demonstration of the commitment Vector and its contractors place on safety, with keynote presentations reinforcing the importance of safety excellence being given by the Chief Executives of Vector and our service providers.

A full review is currently being undertaken of Vector's health and safety framework in order to identify potential improvement opportunities. Vector continually strives for excellence in safety performance and recognises the importance of a robust, well structured safety framework to assist in delivering an incident and injury free workplace.

8.6.3 Safety Management System for Public Safety

The passing of the Electricity Amendment Act 2006 and Gas Amendment Act 2006 required companies in New Zealand engaged in the generation, transmission and distribution of electricity or gas to develop, implement and maintain a Safety Management System that will ensure their generation and distribution systems will not pose a significant risk of serious harm to members of the public risk or of significant damage to public property. Vector is well positioned to meet the requirements of the new regulations and intends to review and update its current policies and practices in preparation for an external audit that is to be completed before April 2012.

8.7 Environmental Management

8.7.1 Environmental Policy

Vector's environmental policy confirms its commitment to managing the environmental impact of its businesses, and ensuring compliance with legislation and standards. The company conducts its operations in such a way as to respect and protect the natural environment, and is committed to continual and progressive improvement in its environmental performance. Sufficient competent resources and effective systems are provided at all levels of the organisation to fulfil this commitment. Vector also requires all employees and service providers working for Vector to manage their employees and work for Vector in line with this policy.

Vector's environmental policy is to:

- Ensure environmental considerations are part of all business decisions;

- Meet or exceed all relevant environmental legislation, regulations or codes;
- Participate and work with government and other organisations to create responsible laws, regulations, standards and codes of practice to protect the environment;
- Monitor and continuously improve our environmental performance;
- Operate in a manner that minimises environmental and social impacts;
- Take appropriate action where there is a negative impact on the environment and a material breach of the Resource Management Act 1991; and
- Communicate with employees, contractors, customers and other relevant stakeholders on environmental matters.

To achieve this Vector:

- Has plans in place to avoid, remedy or mitigate any adverse environment effects of our operations; and
- Focuses on responsible energy management and will practice energy efficiency throughout all of its premises, plant and equipment, where possible.

The long- term operational objectives of Vector are to:

- Utilise fuel as efficiently as practicable;
- Mitigate, where economically feasible, fugitive emissions and in particular greenhouse gas emissions;
- Wherever practicable use ambient and renewable energy; and
- Work with our customers to maximise energy efficiency.

8.7.2 Environmental Practices

Vector also puts significant emphasis on environmental management and continues improving its environmental management in partnership with our FSPs. Vector's key practices in this regard include the following:

- Vector continually explores opportunities for minimising waste generation and, when identified, pursues economically viable opportunities consistent with business priorities and community expectations. All wastes generated from our operations are effectively managed and disposed of in a cost effective manner in compliance with statutory requirements;
- When addressing environmental issues, consideration is given to both long-term impacts of waste disposal and to potential long-term issues;
- One of Vector's key performance indicators (KPIs) is to avoid any activity that would cause Vector to be in breach of the Resource Management Act 1991;
- Vector's safe work practices manual includes minimum acceptable standards on environmental management and a focus on eliminating damage; and
- Environmental incidents are reported, recorded and investigated with any learnings and improvements shared across our FSPs at the safety leadership forum.

Electricity
Asset Management Plan
2011 – 2021

Expenditure Forecast and Reconciliation – Section 9

[Disclosure AMP]

Table of Contents

List of Tables

List of Figures

9. Expenditure Forecast and Reconciliation

This section summarises how the capital, operating and maintenance expenditures are compiled, including prioritisation of projects. The budget for the 2010/11 regulatory year as well as the expenditure forecasts for the 2011/12 to 2020/21 regulatory years (RY) are also presented.

As Vector operates to a June financial year all its budgeting, financial and management reporting activities align with the June year. However, the Commerce Commission's Electricity Information Disclosure Requirements 2004 require Vector to disclose its AMP and the respective expenditure information on a March year basis, as presented below. There are, therefore, time shift differences in the expenditure forecast disclosed in this AMP compared to the budget Vector operates to and figures that may be reported in our financial statements or elsewhere.

Due to the difference between the regulatory calendar and Vector's corporate planning cycle the Board has not yet approved the 2011/12 budgets and the 2012 forecasts are, therefore, still subject to change. In addition, while the expenditure forecasts for later years presented in this AMP are the best estimates available at the time of preparing this plan they will be subject to change in future as circumstances change and projects are reviewed.

It is possible Vector will need to apply to the Commerce Commission (the Commission) for a "customised" price path, which takes into account future capital expenditure (capex) requirements. In that event, Vector would be locked into a five year capex forecast which would underpin prices. While the expenditure forecasts in this AMP have been prepared according to international best practice, Vector would need to review its expenditure plans to ensure they provide a suitable basis for such a fixed price path.

9.1 Expenditure Forecast

9.1.1 Capital Expenditure

Vector's capex forecast for the financial years ending 31 March from 2012 to 2021 is set out in Table 9-2.

This is our forecast of the expenditure required to achieve Vector's customer, network and business goals and execute the asset management activities described in this AMP. The capital expenditure is presented under the following categories:

- Customer connection, covering reticulation of subdivisions, building customer substations, and connecting customers to the distribution network;
- Network growth, covering augmentation of the distribution network to provide capacity and security to cater for demand growth and solutions to supply quality issues resulting from demand growth;
- Asset replacement and renewal, covering replacement and refurbishing network assets to address condition related issues;
- Reliability, safety and environmental, covering work to ensure network reliability and to address safety and environmental issues; and
- Asset relocation, covering the moving or replacement of distribution network assets where requested by requiring authorities, and under-grounding overhead lines to satisfy Vector's obligation under the AECT trust deed.

While these estimates have been prepared based on the best information at Vector's disposal, it should be noted electricity distribution businesses are still experiencing a period of significant economic volatility. Factors that may materially influence investments levels going forward include:

- Economic cycles and the impact of these on electricity demand. At the time of preparing the previous two AMPs (covering the period between April 2008 and March 2010) New Zealand was entering into and emerging from a major economic downturn, respectively. This downturn initially did not result in the anticipated electricity demand or connection slowdown. With signs of recovery starting to surface towards the second half of 2009 it was anticipated demand and energy delivery would start to grow. However, based on our recent experience (unaudited), the 2010 electricity consumption appears to be weaker than in 2009 This could be a short-term fluctuation rather than indicative of ongoing economic pressure, but recent press reports indicate the economic recovery appears to have stalled (with GDP growth for the second and third quarter of 2010 at 0.1% and -0.2% respectively);
- At the time of preparing this AMP, Christchurch experienced a major earthquake. This is anticipated to have a serious impact on the New Zealand economy, but at this stage it is not yet clear how that would play out in the Auckland region. The potential economic impact, and that of possible population movements, have not been taken into account in this plan. The situation is being reviewed and will be reflected in future plans;
- The Government launched an infrastructure programme that brought forward a number of construction projects. This requires some major network projects (for example, to supply electricity to the Waterview tunnel and the Victoria viaduct tunnel) and gave rise to substantial services relocation projects[1];
- After a long period of relative stability, electricity distribution and consumer technologies are now undergoing rapid change (see discussions in Section 3). New applications, associated with more intelligent networks, are arising that could have a substantial impact on how networks develop in the medium to longer term future, and hence also on the associated expenditure patterns[2];
- The requirement for the Commission to set Input Methodologies was introduced in the 2008 amendments of the economic regulation provisions of the Commerce Act. The amendments were intended to address concerns with regulatory instability and uncertainty and emphasised the importance of the Commission ensuring both certainty and incentives to invest. Vector does not believe the Input Methodologies for Electricity Distribution Services, finalised in December 2010, provide an adequate level of certainty or investment incentives. In addition, the assessment of the P_0 adjustment will not be finalised until late 2011 and the methodology by which this will be implemented remains highly uncertain. It is possible electricity distribution businesses will face significant downward price adjustments as a result of the assessment. It is also possible the Commission will invoke the clawback provision for up to two years worth of revenue over the P_0 adjusted revenue (from 2010 through to 2012). This creates significant uncertainty for electricity distribution businesses and impacts on their ability to invest;
- A number of significant issues have been clarified through the Input Methodologies' development process. However, Vector considers the uncertainty created by the lack of a defined starting price adjustment process, in conjunction

[1] One potential outcome from the Christchurch earthquake may be that infrastructure projects in Auckland will be delayed. This has not been considered for this AMP.

[2] At the time of finalising this AMP, a major earthquake and associated tsunami caused major damage to parts of Japan. While too early to assess the current impact, in the past events like this has been a catalyst for rapid technological development in replacement technologies and technology standards. Such potential developments will be considered in future versions of the AMP.

with a Weighted Average Cost of Capital (WACC) Input Methodology which we believe will set returns below commercially realistic levels, will create difficulties for electricity distribution businesses as they attempt to make investment decisions and attract investment capital. If these decisions restrict Vector's ability to re-invest in its network Vector may need to review its current investment plans;

- It is not clear whether future regulatory incentives and/or customer expectations will support investment in reliability improvements. The Commission has indicated it will consult on regulatory mechanisms to incentivise quality of supply improvements or ways of improving energy efficiency in the future. However, the Commission has given no assurances such incentives will be implemented, despite a clear requirement in the legislation to provide incentives to invest in energy efficiency. These incentives will be essential to improve quality of supply and energy efficiency on distribution networks. In the absence of such incentives, investment may only meet the current regulatory requirement to maintain network performance and quality of supply at its historical levels; and

- A key element of the regulatory regime is the basis of establishing the value of the regulatory asset base (RAB). The Commission, in its final input methodology determination issued in December 2010, decided that the 2004 Optimised Deprival Valuation (ODV) indexed forward at CPI will be used as the opening RAB instead of a new asset valuation using labour and material cost data that reflects the competitive market price for electricity distribution at the start of the new regulatory regime (2010). Vector considers that valuing the opening RAB with a new up to date ODV, which reflects the value at which a willing investor (who had not yet invested) and a willing regulator would enter into a long term contract in a workably competitive market, is the theoretically correct starting RAB value for the new regulatory regime. The three main effects of a new ODV are to reflect changes in input prices, over and above CPI, since the last ODV, allow adjustment for any errors in or improvements to the previous ODV and to allow for a reassessment of the optimisation – reflecting critical factors such as the continuing strong growth in demand referred to above. Valuing the starting RAB using a 2010 ODV would also be consistent with past regulatory decisions as under the previous threshold regime a new ODV was to be undertaken in 2008, but this has not eventuated. The propensity for the Commission to fundamentally change its approach breaches regulatory best practice and introduces significant uncertainty into the likely future shape of the regime. Vector believes this regulatory uncertainty will also have a significant dampening effect on the willingness and ability of electricity distribution businesses to invest.

To accurately accommodate this level of uncertainty in a ten year investment programme presents considerable difficulties. To reflect this, Vector forecasts an upper and a lower expenditure level as shown in Figure 9-1.[3]

[3] This expenditure range differs from that set out in the 2010 AMP to reflect the factors discussed in Section 9.3.1.

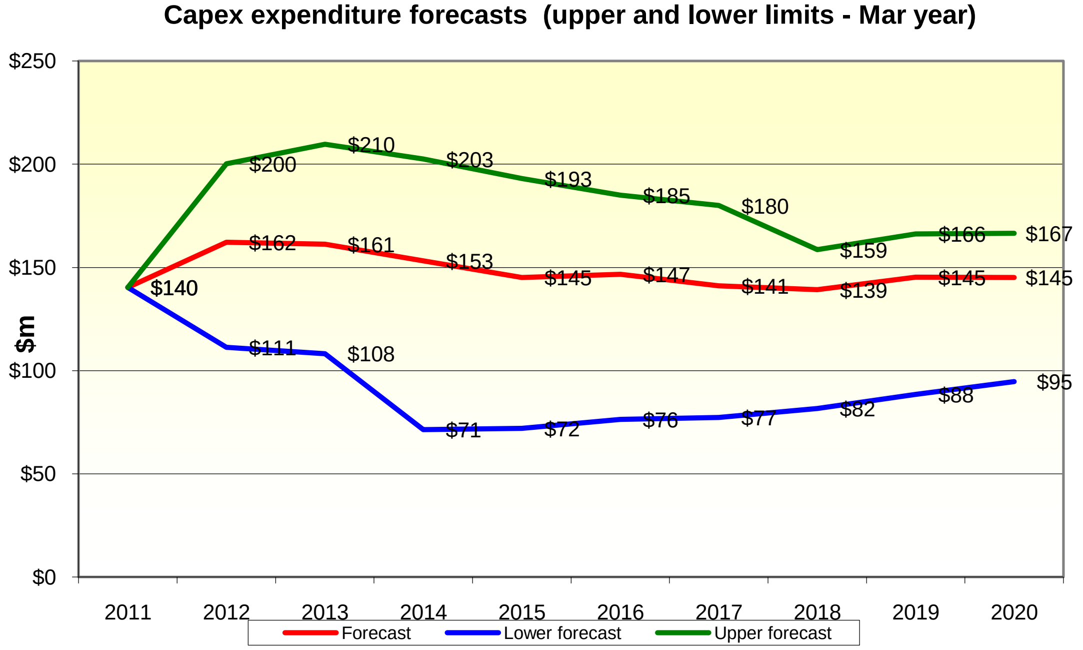


Figure 9-1 : Forecast capital expenditure range

The lower line represents minimum expenditure Vector must commit in order to comply with its legal obligations, deal with known health, safety and environmental issues, and provide sufficient network capacity to just meet peak demands under normal conditions, but without necessarily maintaining security of supply under fault conditions.

It includes the minimum essential expenditure on planned asset replacement, network performance improvement, customer growth (only where Vector is obliged to supply) relocation projects (where Vector is obliged) and security of supply based projects. The currently committed under-grounding programme is assumed to continue.

This expenditure profile is not sustainable in the medium and longer term and would result in increasing asset failure rates and breaching of Vector's security of supply criteria. This would result in a reduction in customer service levels (reduced reliability and extended outages due to lack of back stopping capability) and sharply increasing operational expenditure on fault response and customer complaints. Furthermore, this scenario represents a running down of Vector's assets which would not only lead to deteriorating network performance but would also defer expenditure until a very substantial replacement requirement arises in the medium-term future. Vector would, therefore, be very reluctant to embark on this profile and would only do so if forced to by excessive regulatory uncertainty and risks around achieving a commercially realistic return on investment.

The upper line represents expenditure levels that would allow Vector to achieve a substantial step improvement in network performance (as opposed to current forecast expenditure levels, which are targeted at maintaining current performance levels). This higher expenditure would enable Vector to:

- Effect major, rapid improvements in the quality of service (reliability) provided by the network;
- Accelerate asset replacement rates to improve age profiles;

- Underground selected parts of the network where external interference is currently impacting on reliability[4];
- Substantially reduce maintenance expenditure;
- Invest in a relatively rapid roll-out of smart network technologies to build on the substantial investments made in the past decade; and
- Significantly enhance network security of supply performance.

9.1.2 Maintenance and Operations

Vector's forecast maintenance expenditure for the 2011 financial year and the expenditure forecast to 2020 are listed in Table 9-2.

Vector's operating expenditure is grouped under the following categories:

- Routine and preventative maintenance covering the cost of planned regular maintenance of distribution assets to maintain their service capability and avoid premature failure.
- Refurbishment and renewal maintenance covering the cost of replacing assets that have failed or likely to fail soon.
- Faults and emergency maintenance covering the cost of fault repairs and attending to emergency situations such as storms to effect restoration of supply.

If the upper or lower capex scenarios discussed previously are adopted this would have a direct impact on the maintenance expenditure resulting in upper and lower range expenditure as reflected in Figure 9-2.

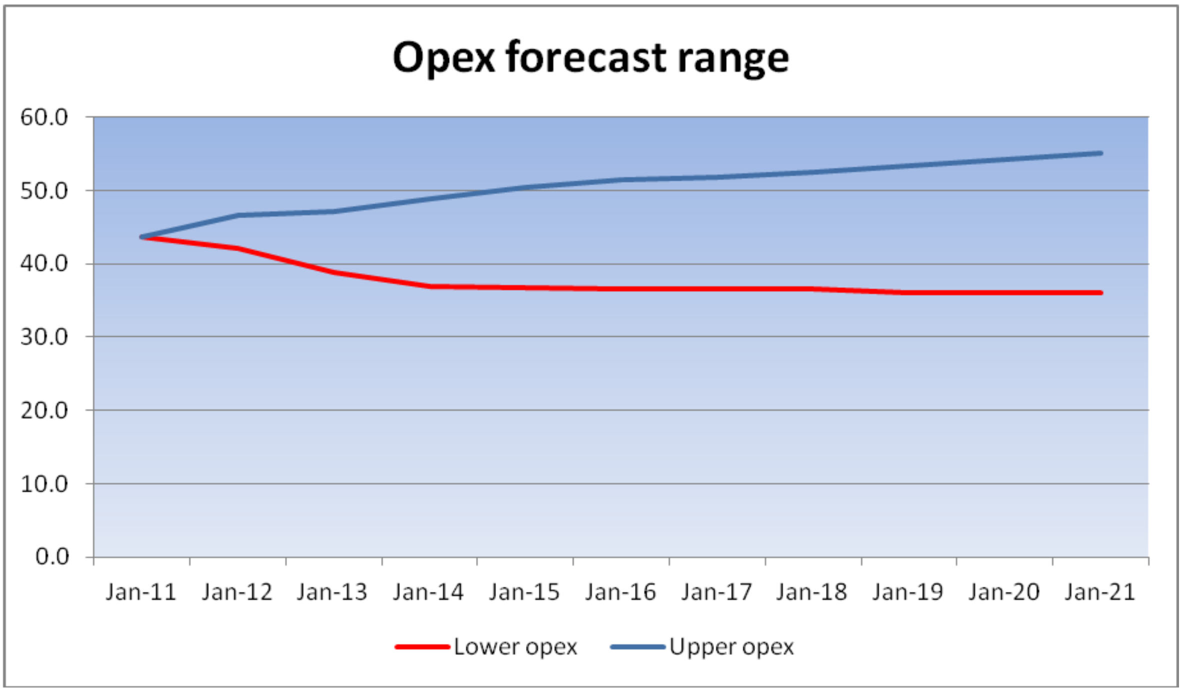


Figure 9-2 : Forecast opex range

[4] Vector has an ongoing under-grounding program, but the scope of this is based on meeting the AECT Trust Deed obligations. For more discretionary under-grounding, the focus would rather be to reduce external network interference (such as car versus pole incidents) on parts of the network where this occurs frequently.

Adopting the lower capex range, in which the general asset base would be allowed to age and no major network improvements would be implemented, would cause escalating fault and maintenance expenditure.

Should the high capex scenario be adopted, the average network age would decrease (higher proportion of new assets) and there will be substantially increased levels of network automation (as measured against the current provisional capex programme). The net effect of this is that the fault frequency should reduce (especially in the first three years), as well as maintenance costs. There would also be a reduced requirement for renewal maintenance.

9.2 Prioritisation of Expenditure

Section 1 of this document explains the relationship between Vector's goals and strategies, its asset management and investment strategies and policies and how these are used to guide the capital and maintenance works programme.

Section 5 of this AMP details the planning policies and standards, industry information, grid and grid exit point information, load growth data, asset capacities, network operations information and network data required for the preparation of a ten year network development plan. A ten year expenditure projection on customer and growth works programme has been prepared, based on the network development plan.

Section 6 of this AMP details the asset inspection, maintenance, replacement and refurbishment policies and standards. A replacement and refurbishment programme has been prepared for each asset category, based on these policies and standards and taking into account the information on asset age and condition and unit rates (material and labour). Following from this works programme, a ten year capital and operating expenditure projection on maintenance and replacement has been prepared.

Similarly a programme for under-grounding in the Southern region has been prepared in accordance with the requirement laid out in the AECT Trust Deed. An asset relocation programme is also identified based on information available from roading and local authorities.

An appropriate prioritisation process has been developed in line with Vector's strategies and goals to ensure those projects of the highest importance and with the highest cost-benefit are implemented. A five band prioritisation matrix has been developed to rank all projects identified in Section 5 and Section 6, as illustrated in Table 9-1 below. The prioritisation process includes assigning a score to each of the projects based on an understanding of the purpose, value and risk of the project. The projects are ranked according to the scores, with a ranking of one being the highest priority.

	Growth	Integrity	Customer	Legal, Regulations	H&S, Risk, Environmental	Financial & Others	Operational Improvements
1	• Capacity breach leading to asset damage	• Reactive replacement – critical assets		• Legal breach • Breach technical regulations • Regulatory breach	• Direct, serious safety threats • Direct serious environmental threats • Mitigation of extreme and very high risks • Critical cyber security breach	• Overhead Improvement Programme	
2	• Capacity breach	• Asset condition 1 - severe deterioration of asset, high risk and high consequence of asset failure	• Contractual obligations • Relocations • New connections (NPV>0) • Capacity increase (NPV>0) • Customer funded projects	• Regulatory compliance & improvement	• Anticipated serious safety threat • Anticipated serious environmental threats • Mitigation of high direct risks • Serious cyber security breach	• Avoiding financial bleeding on assets	• IT & information support critical for AI ops
3	• Security of supply breach • Network efficiency enhancement	• Asset condition 2 - asset at the end of technical life; increased risk of asset failure and of material consequence; costing more to maintain & operate than to replace	• Other new connections • Other capacity increases • Addressing customer demands		• Medium term safety & environmental improvement projects	• Improved efficiency • Allows capex deferral	• IT & information supporting effective AI ops • Pilot projects, testing new initiatives
4	• Safeguard future options • Enhance network efficiency	• Asset condition 3 - steady state asset replacement programmes • Reliability improvements				• Other NPV>0 opportunities	
5	• Discretionary						

Table 9-1 : Asset investment Prioritisation matrix

9.3 Factors Influencing the Expenditure Forecasts

In preparing this AMP and the expenditure forecasts, several factors contributed to some significant changes in the capex forecasts, as compared with that disclosed in 2010. The main factors are discussed below:

- As part of Vector's ongoing efficiency drive, all planned capital works for the AMP planning period were subjected to detailed further review prior to commitment. Through a combination of innovation, judicious investment allowing deferment of major installations, higher asset utilisation and better focused renewal expenditure, the capex investment plan now shows a significant saving over that proposed in 2010.
- The exception to this is the significant increase in expenditure forecast for RY12. This is largely as a result of bringing forward three large projects from their originally forecast commissioning dates (RY13 and RY14) for substantial completion in RY12, to meet third party requirements.
    - The construction supplies for NZTA's planned Waterview tunnel project are now required in RY12 (brought forward from RY14).
    - The Vector works associated with the new GXP at Hobson Rd is now to be largely completed in RY12 to work in conjunction with Transpower's programme on the NAaN project. This was initially scheduled for RY14. In addition, the scope of the project has increased from that originally foreseen. Following completion of the initial designs for the GXP Vector now has a far more detailed understanding of the complexity and resulting cost involved with erecting major infrastructure projects simultaneously for two parties, on a congested, live CBD site with restricted access and available space.
    - Similarly, the commissioning date for the Wairau Rd GXP is now intended for early RY13, with most of the work to be done in RY12 – almost a year earlier than originally foreseen. The scope for this project has also increased materially.

  (It is noted that the expenditure impact of bringing forward these projects is anticipated to be significantly offset by the deferral of several major projects from their originally planned RY12 construction dates, largely as a result of Vector's efficiency drive.)
- There are also a number of significant, new customer driven and relocation projects identified for the next two years. This includes Transpower's planned replacement of the outdoor switchgear at Pakuranga and Penrose substations to indoor switchgear, which will require considerable reconfiguration of Vector's outgoing circuits. Expansions at the Auckland Airport have also been accelerated from that originally foreseen.
- In addressing Vector's obligation to the AECT, work on the undergrounding programme is anticipated to be accelerated in FY12 to offset some project delays incurred in FY11.

9.3.1 Comparison of Expenditure Forecasts

The net effect of all of these adjustments is to accelerate near-term growth expenditure over those previously forecast, with a reduction in the later years. This is illustrated in Figure 9-3, where the forecast capex profile under the present AMP (2011) is compared with the previous forecast (2010). The previous forecast has been adjusted for inflation[5] to enable meaningful comparison between the two forecasts.

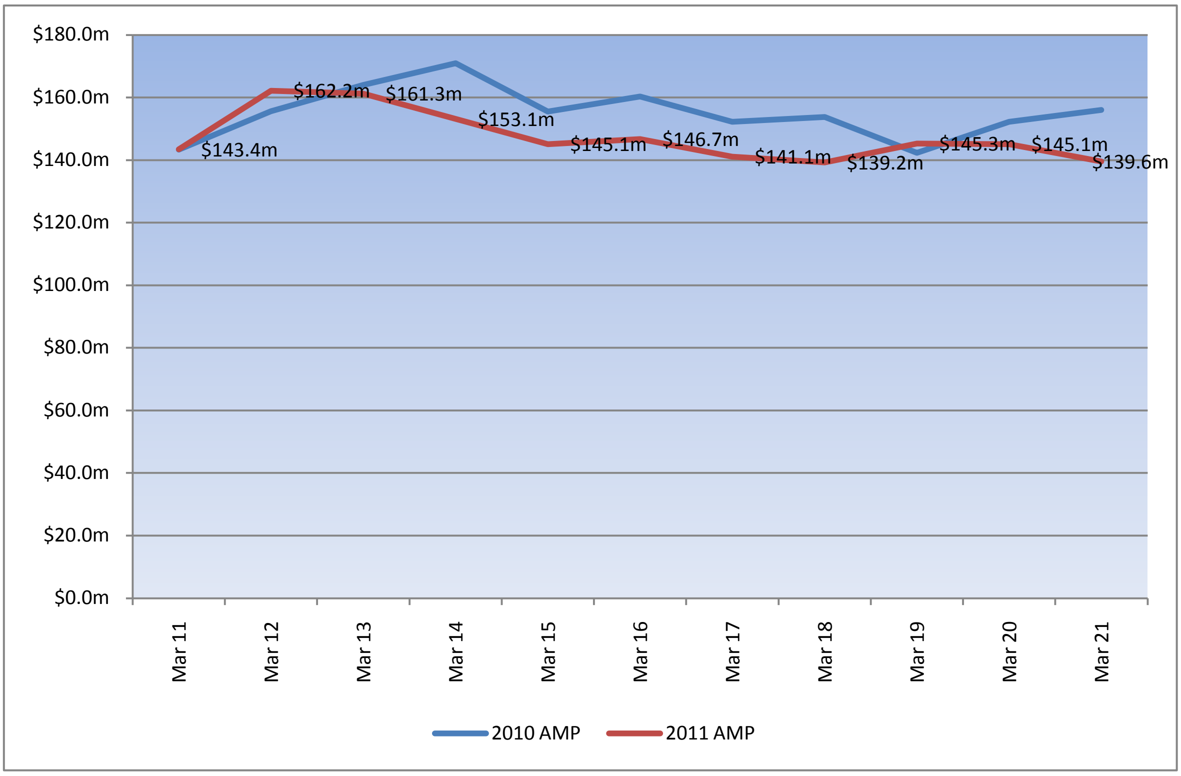


Figure 9-3 : Comparison of capital expenditure profile between this AMP and the previous forecast

9.4 Reconciliation of Actual Expenditure against Budget

Table 9-2 below summarises the capital and O&M expenditure projection of the electricity business over the planning period for all capital and operating expenditure categories. The forecasts were prepared based on Vector's financial year (from 1 July to 30 June of each year) and were converted to the regulatory financial year (from 1 April to 31 March of each year) using a 25%:75% proportional allocation[6]. It should be noted that in reality, the spending profile is not evenly distributed throughout the year. This increases the variance between the actual expenditure and the budget as presented.

[5] Vector uses the Producer Price Index (PPI) as basis for calculating escalation in expenditure on the electricity network. Over December 2009 to December 2010 (the respective dates at which cost estimates for the 2010 and 2011 AMPs were prepared), the PPI increased by 4.3%. The Reserve Bank indicated the rise in GST in 2010 had a minor impact on the PPI, but did not provide any figure. Reflecting this, we used an escalator of 4% to project the 2010 AMP figures forward for the 2011 AMP.

[6] For example, the forecast for the regulatory year ending 31 March 2015 is made up of 25% of the forecast for the Vector financial year ending 30th June 2014 and 75% of the forecast for the Vector financial year ending 30 June 2015. This is with the exception of the first year of the planning period (year ending 31 March 2011) for which the forecast for the Vector financial year (ending 30 June 2011) was adopted.

10 Year Forecast of Expenditures	Mar 10 Actual	Mar 11 Budget	Mar 12 Forecast	Mar 13 Forecast	Mar 14 Forecast	Mar 15 Forecast	Mar 16 Forecast	Mar 17 Forecast	Mar 18 Forecast	Mar 19 Forecast	Mar 20 Forecast	Mar 21 Forecast
Customer connection	16.8	17.5	21.6	22.0	22.2	22.4	22.5	22.6	22.6	22.6	22.6	22.6
System growth	31.7	43.3	55.5	50.6	45.0	41.0	43.1	42.2	39.4	46.4	44.9	41.0
Asset replacement and renewal	42.5	47.5	55.9	63.2	62.7	59.5	59.8	55.2	56.1	55.2	56.5	54.9
Reliability, safety & environmental	1.7	4.5	3.4	4.0	3.8	3.2	2.8	2.8	2.8	2.8	2.8	2.8
Asset relocation (including undergrounding)	21.3	23.3	25.8	21.6	19.4	19.1	18.5	18.3	18.3	18.3	18.3	18.3
Capital Expenditure Subtotal	114.0	136.1	162.2	161.3	153.1	145.1	146.7	141.1	139.2	145.3	145.1	139.6
Routine & preventive maintenance	14.3	13.7	19.6	19.8	19.7	19.9	19.9	20.0	20.0	20.1	20.2	20.3
Refurbishment & renewal	10.8	11.8	11.6	12.0	11.9	11.9	11.0	10.7	10.7	10.8	10.7	10.7
Fault and emergency	15.8	14.9	13.0	13.1	13.1	13.2	13.3	13.3	13.4	13.5	13.6	13.6
O & M Subtotal	41.0	40.4	44.2	44.8	44.8	44.9	44.1	44.0	44.2	44.4	44.5	44.7
Total Direct Expenditure	155.0	176.5	206.4	206.0	197.9	190.1	190.8	185.1	183.4	189.7	189.7	184.3
Overhead to underground	12.5	12.7	17.3	13.4	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

* Figures are in January 2011 dollars (million);

** The year reference indicates the end date of the financial year

Table 9-2 : Asset management plan expenditure forecast

Table *9-3* summarises the actual 2010 financial year expenditure against the budget for the year for all capital and operating expenditure categories. An explanation for variances over 10% is provided below:

- The higher than budget expenditure in the "Customer Connection" category ($6.8 million) was mainly due to a lower budget for the year developed in anticipation of an economic recession. In reality the numbers of connections continued at a similar rate to last year (active electricity connection numbers increase for 31 March 2008: 6187, 31 March 2009: 4886, 31 March 2010: 4947 (Source: Data Warehouse)). The expenditure was in line with the numbers of connections achieved.

- The actual expenditure in the “System Growth” category was below budget by $7.0 million. This was in part due to Vector’s capital efficiency drive (which resulted in the deferment of a number of projects and cost-reductions in projects that carried on over the period), as well as the near completion of a number of large multi-year projects (i.e. zone substations at Clendon, Greenhithe, St Johns, Otara, Pt Chevalier) and the return of the unused contingencies associated with these projects. (Contingencies are included in the forecast capital expenditure programme.) The “under-spend” was exaggerated this year with so many large projects nearing completion.

- The budget for “Reliability, Safety and Environment” category was under-spent by $3.9 million. Funds have been transferred to asset replacement and renewal as it has been identified that there has been a reduced need for asset performance improvements (mostly due to exceptionally good weather conditions). The under-spend in renewal and replacement area of works was due to timing and unspent contingency before 1st April.

- “Asset Relocations” category has split between “Overhead to Underground Conversion” and “Asset Relocations” expenditure. The actual expenditure ($12.5m) for “Overhead to Underground Conversion” was similar with the budget ($12.2m). The asset relocations budget forecast was based on an anticipated downturn in the economy due to the recession. To compensate for the anticipated commercial sector down-turn, the government advanced a number of infrastructure projects. The key projects included various motorway extensions (SH20, SH16 and SH1). The result was an upswing in the amount of work Vector needed to do to relocate our assets that were in the way of these projects. This accounted for the increase in relocations expenditure during the year.

- The expenditure in the “Routine & Preventive Maintenance” and “Fault and Emergency” categories appeared to be $3.5 million above and $4.1 million below the budget respectively. This was in part due to the manner in which expenditure was categorised at the time and a different approach adopted during the year. Some activities were shifted between the two groupings. In addition, the Auckland region experienced a relatively benign weather year and network storm damage was substantially below the historical average.

- The “Refurbishment and Renewal maintenance” appeared to be $2.7 million under budget. The routine and preventive maintenance identified the assets to be refurbished and renewed. The under-expenditure was due to a combination of timing differences and a reduction in the actual number of assets identified for refurbishment in this period.

Variance between Actual and Previous Year Forecast	Mar 10 Actual	Mar 10 Budget	Variance[7]	Variance %
Customer connection	16.8	9.9	6.8	68.6%
System growth	31.7	38.7	(7.0)	(18.1%)
Asset replacement and renewal	42.5	42.1	0.4	(1.0%)
Reliability, safety & environmental	1.7	5.7	(4.0)	(69.7%)
Asset relocation (including undergrounding)	21.3	18.9	2.5	13.1%
Capital Expenditure Subtotal	114.0	115.3	(1.3)	(1.1%)
Routine & preventive maintenance	14.3	10.8	3.5	32.7%
Refurbishment & renewal	10.8	13.5	(2.6)	(19.6%)
Fault and emergency	15.8	20.0	(4.1)	(20.7%)
O & M Subtotal	41.0	44.2	(3.2)	(7.4%)
Total Direct Expenditure	155.0	159.5	(4.5)	(2.8%)

Table 9-3 : Asset management plan expenditure reconciliation

[7] Variance equals actual expenditure minus budgeted expenditure.