2023—2033

electricity asset management plan

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SECTION 01

Introduction

1 – Introduction

1.1 Abstract

Electricity distribution businesses face the need for unprecedented investment to support future demand and be resilient against climate change. These factors are exacerbated by the impacts of high inflation. Vector is proposing investment of $537m additional capital expenditure over the first five years of this AMP period before inflation, compared to the forecasts in our last AMP. With this additional expenditure, our updated capital investment plans covering the full AMP period (2023-2033) total $4.3 billion. This increased level of investment is required to meet growth, reliability and resilience needs.

Vector believes the way to achieve more long-term affordability for customers is through increasing deployment of non-wires alternatives and effective orchestration of manageable load and injection, over the long term. Since increasing electricity demand is a function of New Zealand's decarbonisation effort, accommodating this demand in an affordable way results in a more affordable decarbonisation. Vector is laying the foundations for this in this AMP cycle, through maintaining the significant investment levels as set out in recent AMPs on digital enablement, including for systems such as Advanced Distribution Management Systems, Distributed Energy Resource Management Systems, smart meter data analytics, and network simulation tools.

It's critical to get these foundations in place now to enable more long-term affordability for customers as demand grows significantly in future. The counterfactual, where minimal load is orchestrated as demand grows, and non-wires solutions fail to develop, will set us on a path requiring significantly increasing investment in future years to meet unmanageable demand growth. Regulatory support and incentives are required to avoid the counterfactual.

This Asset Management Plan sets out, as at the date of certification, our view of the investments we believe will deliver the best outcomes for our customers. However, we note that, particularly given the uncertainty over future electricity demand, we are not bound to follow the investments described here as we update our plans and analysis on how to best deliver for our customers. Each investment we make goes through appropriate governance processes to ensure it is delivering against our strategy.

We've included early and preliminary assessments of additional investment needed to boost climate change resilience following the impacts from the Auckland Anniversary flooding and Cyclone Gabrielle. These assessments update our existing climate adaptation plans, however they will change as more analysis is completed in time for our 2024-2034 AMP.

1.2 Executive summary

Electricity distribution businesses are facing the need for unprecedented investment to support a projected significant and sustained uplift in demand for electricity across the economy. This increase in demand for electricity is driven by electrification of transport and process heat in order to reduce carbon emissions, residential growth, and the electricity-intensive infrastructure required for digitalisation, such as data centres.

Significant investment and change is required across the entire energy sector to support this increasing demand in a way that reduces overall carbon emissions from energy use and is resilient against increasing risk from climate change. For example, New Zealand's electricity distribution infrastructure alone requires investment of $22 billion from now till 2030 [1].

At the same time, new and cost-effective asset management technologies and supporting digital and information management technologies are providing opportunities to improve network resilience, customer experience, long-term affordability, and the enablement of new market and innovation opportunities for businesses and households alike.

The proposed investment outlined in this AMP reflects these realities; the need to invest in system growth, climate change resilience, and enabling technologies and capabilities to lay the foundations for more non-network solutions and effective orchestration of distributed energy resources.

There has been a significant increase in inflation levels, compared to recent history. Vector has advocated strongly in recent times for the Commission to cease forecasting inflation for the purpose of setting DPP revenues. This is due to past Commission forecasts being considerably different to actual outturn inflation. Vector has commissioned expert reports [2] which highlight the difficulties in forecasting inflation. Vector's analysis for the current DPP finds that adjusting for actual and latest inflation forecasts through the current DPP period, the DPP3 capex allowance should be $155m higher compared to using the inflation assumptions used by the Commission in setting the DPP3 capex allowance. This further highlights the need for the regulatory regime to be designed in a way that removes inflation forecast errors so that the impact of these errors are not borne by suppliers or consumers.

Inflation is impacting all expenditure categories and is at a level that if the required works are undertaken then Vector will not recover its investment due to penalties incurred from the overspend of DPP allowances. Alternatively, if the required works are not undertaken this introduces network and security risks.

Against this high inflationary environment, there is also a strong increase in the investment needed for system growth investment, and climate change adaptation.

The need for system growth investment is driven by large-scale customers driving increased reinforcement investment, such as a data centre boom in Auckland, Auckland Transport fleet electrification, as well as accelerated organic load growth from continued residential development, fuel switching from gas to electricity, and Vector's updated scenario modelling showing

[1] https://www.bcg.com/publications/2022/climate-change-in-new-zealand

[2] https://www.vector.co.nz/about-us/regulatory/submissions-electricity

higher residential EV charging uptake. To account for this uplift in system growth, Vector is forecasting capex around $120m above the current DPP capex allowance, over the remaining two regulatory years of the current DPP. Vector's customers pay a development contribution which recovers the costs for Vector of this system growth over time, however against increasing reinforcement and growth costs, this development contribution may need to increase. We also intend to review our capital contributions policy following the IM review and communication of DPP4 draft decision.

Increased resilience (network hardening) investment to adapt to the impacts of climate change is essential, not only to safeguard customer experience against increasing risk of weather-related disruption, but also due to the increased reliance on the electricity system for energy, transport and the digital economy. The level of investment required now for network hardening is not recoverable through the current DPP3 allowances. Vector's view is that future DPP cycles must do more to account for the need for EDBs to invest in network hardening for climate change resilience. Extreme weather events affecting Auckland such as the April 2018 storm, Auckland Anniversary 2023 flooding, and Cyclone Gabrielle of February 2023 make this clear. Early and preliminary forecasts in this AMP have set an additional investment at around $135m through the DPP4 period, although we will more fully quantify the additional investment needed once further analysis is completed in time for our 2024-2034 AMP.

1.3 Affordability for customers

Vector continues to place our customers at the centre of our decision making, balancing reliability and resilience investments with impacts on affordability for customers and decarbonisation.

How electricity is generated, transported, stored, traded, and consumed is rapidly changing and will continue to evolve. These changes are driven by customers, and so Vector employs a data first strategy, complemented by direct engagement, to build deeper understanding of customer preference and impact. This strategy is crucial, given the scale of our customer base and operations, noting that in Auckland many suburbs are the size of New Zealand towns and small cities. Our customer engagement strategy is described in Section 4.

An example of how this strategy informs our work is our customer pricing methodology, which is informed by data analysis that examines billing and half-hourly electricity use data across different customer parameters such as deprivation deciles. This enables pricing decisions to be made with detailed knowledge of aggregate and customer level impact, helping to avoid negatively affecting financially vulnerable customers.

Our forecasts show that peak demand growth by 2052 will be predominantly driven by the electrification of transport and the substitution of gas water heating to electricity. The energy storage properties of batteries and hot water cylinders in these loads (which are referred to as Distributed Energy Resources) make them suitable for demand-side response and allows for the load to be shifted away from peak times through orchestration. There is therefore a significant opportunity to reduce actual peak demand growth through effective orchestration of Distributed Energy Resources (DERs).

Vector has developed a Future Technology Roadmap to guide our investment decisions in building this capability for effective DER orchestration at scale, both managing resources directly ourselves and coordinating with third parties, since many different participants in the electricity sector are deploying technology and developing the capability to manage such resources.

Critically, the capabilities, infrastructure, and systems set out in our Future Technology Roadmap, are a more affordable way of meeting future demand than building more network. The Future Technology Roadmap also guides investment for Vector to leverage the benefits of non-wires alternatives, by enabling local flexibility market development for the New Zealand energy sector. We recognise this market does not currently provide commercially viable solutions for EDBs, particularly as penetrations of DER are low, however we have signposted the network areas that we believe are best suited to non-network alternatives and are working in a number of forums to help grow this market.

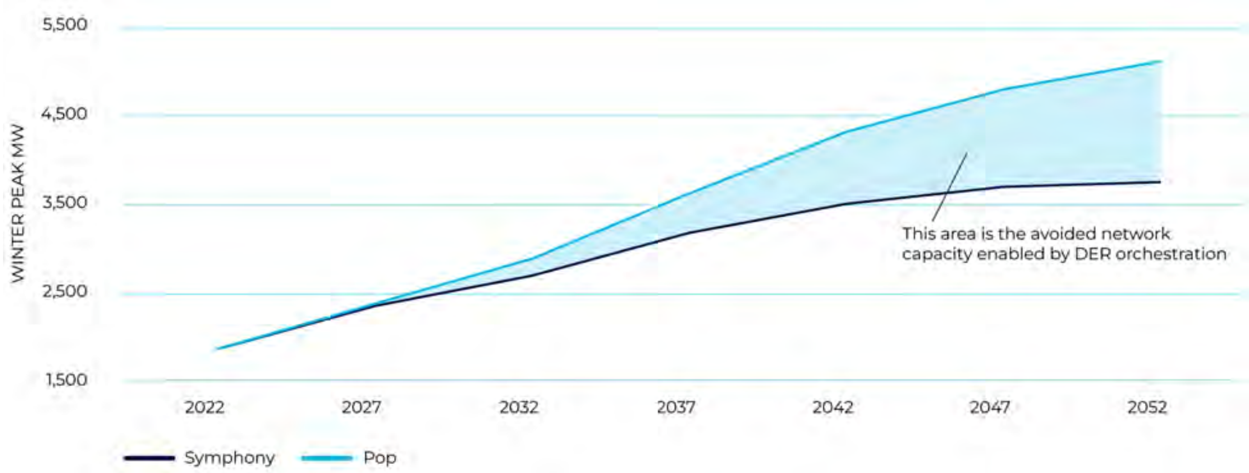

FIGURE 1.1: LOAD FORECAST FOR THE VECTOR NETWORK, WITH AND WITHOUT EFFECTIVE DER ORCHESTRATION

1.4 Critical decade for unlocking affordability

The period to 2033 (AMP 2023) is a critical decade for unlocking longer term affordability. Higher peak demand requires more network investment, which is passed on to customers. As shown in Figure 1.1 above, the divergence between the more costly light blue line and the more affordable dark blue isn't significant in this AMP period (2023-2033), however it will increase significantly in future AMP periods. To enable investment aligned with the lower-cost dark blue line, it's critical to get the building blocks for effective DER orchestration in place now (including digital enablement and regulatory support), so that the benefits can be realised in future AMP periods.

The following are key to unlocking this longer-term affordability:

- The Symphony forecast in the figure above is an optimisation for Vector's distribution network costs which reflects the actions we can take under our regulatory regime. It should be noted that effective orchestration must take full account of customer needs, ensure the network and customer requirements are met, and consider whole of system benefits. Further guidance will be required to assist EDBs in incorporating and valuing these benefits in network planning processes.
- Certainty and confidence that consumers' flexible demand will be shifted outside peak periods with sufficient certainty to defer investment, especially when under management of third parties

1.5 Removing regulatory barriers for an affordable decarbonisation

Our asset management practices can make a significant contribution towards an affordable decarbonisation, provided we can achieve the outcomes described in our Future Technology Roadmap. Unfortunately, regulatory barriers currently exist, making full implementation more difficult. The regulatory framework needs to be effective and forward looking to facilitate the innovation and investment required to boost resilience and achieve an affordable decarbonisation.

We summarise some of these barriers below.

BARRIER	EXAMPLE	RECOMMENDATION
Lack of confidence that consumers' flexible demand will be shifted outside peak periods with sufficient certainty to defer investment, especially when under management of third parties	EDBs can currently directly manage some consumer DERs (e.g. hot water load), but orchestrating third party management using pricing, contracts and other tools does not currently provide the same level of certainty	Regulatory settings should provide EDBs with sufficient certainty of DER management practices (including by third parties) that investment upgrades can be permanently deferred
EDB cashflows are 'back-ended'	Given the significant amount of investment forecast to enable the electrification of transport, gas use, and industrial process heat, 'back-ended' cashflows will likely present significant funding challenges, which we have already observed in Australia	We recommend a move towards more 'front-ended' cashflow, such as what Transpower already benefits from under the same regulatory regime. Note that Transpower faces materially less forecasted capital than EDBs cumulatively
DPP reset allowances set on historic expenditure and lack of guidelines on how to justify a step-change in OPEX expenditure	Enabling efficient connection of new electric loads and integration of new customer behaviours not previously experienced e.g. gas to electricity switching and new commercial loads for Data Centres and transport electrification	We urge the Commission to review the methods by which it determines allowances for OPEX and CAPEX allowances where step changes to historic expenditure is observed. We also believe that the Commission needs to provide clear guidelines on the information required to allow for both OPEX and CAPEX step changes in the setting of price-paths
Lack of standards set for EV charging and connection agreements	Connection standard settings for EV smart charging	We recommend that the Minimum Energy Performance Standards (administered by EECA) are used to ensure that all EV chargers sold or installed in NZ have smart capability and are set to off-peak charging by default. Some Policy support is needed to implement this. Our full set of recommendations, including the role of incentives, and customer installation pathways, are included in our recent response to EECA's their Green Paper: Improving the performance of electric vehicle chargers [1]
Commerce Act does not include investments into decarbonisation	There is no regulatory incentive to lower companies' emissions, such as through the procurement of SF_6 free switchgear	We recommend an amendment in the Commerce Act to include investments into decarbonisation in the same way that energy efficiency was amended in 2009
Ex-post innovation mechanism with limited funding available	Innovation project allowance to handle the decarbonisation transition so that it is in the best interest of consumers	Vector believes that the purpose of innovation under the IMs should be expanded to include an objective on decarbonisation
Lack of clarity over the definitions of generation as a regulated service	EDB use of and/or ownership of generation assets such as network level battery storage and distributed solar	The Commission must clarify the scope of EDB ownership and use of generation assets and promote its decision on this matter in the current IM Review

1 https://blob-static.vector.co.nz/blob/vector/media/vector-2022/vector_eeca_ev_smart_charging_submission_1.pdf

BARRIER	EXAMPLE	RECOMMENDATION
Resource management and planning settings could do more to enable a permissive environment for our electricity distribution assets	About 70% of the consents sought by Vector are approved with no change – signalling the consents add no value while adding an exceptionally high consenting burden for BAU network activities	RMA reform needs to achieve enabling provisions for electricity distribution, which currently has no national direction by way of a National Policy Statement or National Environmental Standard
Uncertainty over gas transition and its impact on electricity demand	Fuel switching from gas to electricity will drive demand changes	National gas transition plan developed
Difficulty maintaining accurate inflation impact on DPP allowances within current regulatory system and unstable inflation environment	The current regime necessitates a 5 year or more inflation forecast for allowances, which presents difficulties when compared with actual inflation impacts.	Remove inflation forecasts error impacts by 1) allowing suppliers to choose whether to CPI index their regulatory asset bases and 2) adjust OPEX and CAPEX allowances to allow for outturn inflation.

1.6 Auckland-specific challenges

While every electricity network is different, some of the challenges faced by the sector are concentrated in Auckland due to the region's population, significant growth and intensification, EV uptake, and potential for local authority goals around lowering carbon emissions to impact on electricity demand.

In Auckland we continue to navigate the challenge of asset encroachment stemming from intensification. Whilst housing development is enabled by a number of policy and legislative levers, compliance with the minimum approach distances set out in the Electricity Code of Practice is often overlooked by developers and builders. We are engaging with Auckland Council to explore adding a mechanism in the Auckland Unitary Plan to ensure compliance with the minimum approach distances. We are also engaging with the RMA reform work currently underway to shape a future resource management and planning regime where such conflicts are prevented. We're doing this because the current situation risks unnecessary cost and delays to developers to remediate non-compliance.

Auckland Council's Te Tāruke-ā-Tāwhiri (Auckland's Climate Plan), goes beyond the National Strategy set out by the Emission Reduction Plan, and includes a number of goals which, depending on future actions taken by Auckland Council to achieve these goals, may influence our planning. Examples could include action taken to accelerate the rate of process heat conversation from gas to electricity in the region; or actions that accelerate the adoption of an electric bus fleet for public transport.

1.7 Climate resilience

We prioritise climate risk as a critical risk for Vector with Board Risk and Assurance Committee oversight. We provide clear and transparent reporting of sustainability risks, opportunities, and metrics through our Annual Report and Task Force for Climate Related Financial Disclosures (TCFD). [1]

In the context of the asset management plan, climate resilience refers to the ability of the electricity network to anticipate, absorb, accommodate and recover from the effects of a potentially hazardous event related to climate change. For detailed information, refer to our TCFD.

1.8 What is in this AMP?

We recognise that much of the information contained in this AMP is highly technical, yet we have attempted to describe our strategies and activities in ways that are accessible and can help those without technical knowledge to learn more about how Vector manages the electricity distribution networks for the Auckland region. For those with limited time to read the full document, we have set out notable changes or additions which we consider may be of interest to a more general audience.

This table sets out, at a high level, notable changes or additions to this year's AMP, illustrating how we have evolved our capability or strategy and which we consider to be useful for our stakeholders and customers to see in our asset management practices.

NOTABLE IN AMP 2023	PURPOSE	FURTHER DETAILS
Future Network Roadmap	The Future Network Roadmap (FNR) details the initiatives and projects that will be undertaken to realise the Symphony outcome of a more affordable future network	Section 2
Customer engagement	Describes Vector's data-first approach to customer analysis, and Vector's comprehensive customer knowledge and engagement framework	Section 4
CBARM processes for proactive maintenance	Shows the evolution and maturating of Vector's CBARM risk-based asset management practices	Section 8

[1] https://www.vector.co.nz/investors/reports

NOTABLE IN AMP 2023	PURPOSE	FURTHER DETAILS
System growth analysis and planning	Shows Vector's detailed growth forecasting, and options analysis framework for decision making in how to meet system growth needs. Includes case study on making publicly available interactive maps with loading and system growth projects, to make information more accessible to stakeholders	Section 10
Signposting opportunities for Non-Wires Alternatives	As the flex market for non-wires alternatives needs development in New Zealand before suitable NWAs can be adopted by EDBs, we have analysed and signposted the most suitable locations on our network for NWA providers to consider in developing and proposing solutions to us.	Section 10
Climate change and resilience	Describes Vector's strategy in response to climate change including network hardening and decarbonisation.	Section 11
Non-network assets	Describes the digital spend required for a modern and evolving electricity distribution network	Section 14

1.8.1 AMP PURPOSE STATEMENT

This AMP is intended to provide transparency to our customers, staff and stakeholders over the context in which we make investment decisions and how our asset management practices support the decision-making process.

1.8.2 AMP PLANNING PERIOD

This AMP covers a 10-year planning period, from 1 April 2023 to 31 March 2033. Consistent with Information Disclosure requirements, a greater level of detail is provided for the first five years of this period.

1.8.3 CERTIFICATION DATE

This AMP was certified and approved by our Board of Directors on 12 May 2023.

1.8.4 OVERVIEW OF VECTOR

Vector is an innovative New Zealand energy company which runs a portfolio of businesses delivering energy and communication services to more than one million homes and commercial customers across Australasia and the Pacific. Vector is leading the country in creating a new energy future through its Symphony strategy which puts customers at the heart of the energy system. Vector is listed on the New Zealand Stock Exchange with ticker symbol VCT. Our majority shareholder, with voting rights of 75.1%, is Entrust. For further information, visit www.vector.co.nz

Vector's electricity distribution network is described in Section 3, and our Asset Management Practice is described in Section 5.

1.8.5 VECTOR'S CORPORATE VISION

Vector's corporate vision is to create a new energy future. Vector's Asset Management Policy supports the achievement of strategic objectives aligned with this corporate vision.

SECTION 02

Future network roadmap

2 – Future Network Roadmap

2.1 Overview

Since the publication of the last AMP, we have:

- Reviewed the Focus Areas of our Future Energy Network Asset Management Objective
- Developed a Future Network Roadmap (FNR)
- Progressed initiatives to drive innovation to enable the network of the future

2.2 Future Energy Network Asset Management Objective

The revised Focus Areas of this objective read as follows:

- Prepare the network for future changes that will be driven by:
  - technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc.
  - environment: climate disruption and network resilience
  - customer: decarbonisation of the economy, electrification of transport, etc.
  - operations: transition to distribution system operator model and whole of system planning
- Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers.
- Facilitate customer adoption of new technology while ensuring a resilient and efficient network.
- Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network.
- Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market.
- Improve our visibility of, and ability to control, the LV network including management of the information required.
- Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

2.3 Future Network Roadmap

2.3.1 SYMPHONY STRATEGY

The Future Network Roadmap (FNR) details the initiatives supporting Vector's Symphony strategy. The premise of Vector's Symphony strategy is that non-network solutions, specifically demand side response, will enable an affordable and fair transition by optimising for distribution network costs as customers deploy distributed energy resources to decarbonise the economy, e.g. the electrification of transport will result in the proliferation of residential and public EV chargers.

In this context, demand side response refers to the integration and orchestration of distributed energy resources (DER) to occur outside network peak, avoiding building significant distribution network infrastructure to meet potentially much higher demand peaks in the future. Future peak demand on the network is forecast by our Customer Scenario Model, which estimates the impact of customer growth, customer behaviours, new energy technology uptake, load management technologies and fuel substitution on the Auckland electricity load (see Section 10.4 for more information on the Customer Scenario Model).

Figure 2-1 shows the winter [1] peak demand forecasts across Vector's network, driven predominantly by the electrification of transport and the substitution of gas water heating as per the Customer Scenario Model. The Pop scenario (top, light blue line) shows the expected increase in peak demand without DER orchestration. The Symphony scenario (bottom, dark blue line) shows the forecasted peak demand with DER orchestration. DER orchestration therefore has the potential to avoid significant distribution network infrastructure since the energy storage properties of batteries and hot water cylinders allow for the load to be shifted away from network demand peak times without impacting the utility value to customers. There is therefore a significant opportunity to reduce actual peak demand growth through effective orchestration of Distributed Energy Resources (DERs).

The Symphony forecast in Figure 2-1 is an optimisation for Vector's distribution network costs which reflects the actions we can take under our regulatory regime.

It should be noted that effective orchestration must take full account of customer needs, ensure the network and customer requirements are met, and consider whole of system benefits. We do expect that there will be circumstances where building distribution network infrastructure enables greater participation by DER in upstream markets, resulting in whole of system cost savings. These could include reductions in transmission and generation investment, and generation operational (fuel) costs. However, these upstream benefits are more difficult to forecast as we do not have direct influence on generation investment plans, wholesale electricity markets, or transmission system investments. Further guidance will be required to assist EDBs in

[1] Vector's network experiences its highest demand during the winter peak. Therefore, the network must be designed to support this peak load. Typical winter peak demand is defined as the demand between 6:00 pm to 7.30 pm on the coldest weekdays in a year.

incorporating and valuing these benefits in network planning processes. Ultimately our Symphony strategy is about delivering for Auckland consumers and will include those investments that deliver whole of system benefits that result in positive outcomes for Auckland consumers.

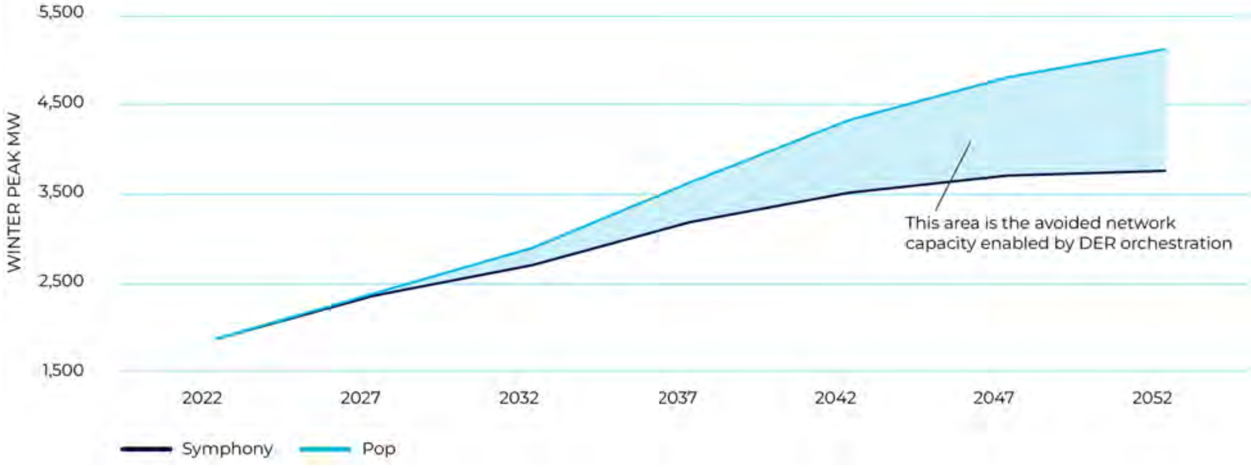

FIGURE 2.1: WINTER PEAK DEMAND FORECAST SCENARIOS

2.3.2 FUTURE NETWORK ROADMAP FRAMEWORK

The FNR consists of three *Pathways* that provide a high-level framework for the new capabilities required to deliver Symphony – Modernisation, Orchestration and Enabling – as shown in Figure 2.2.

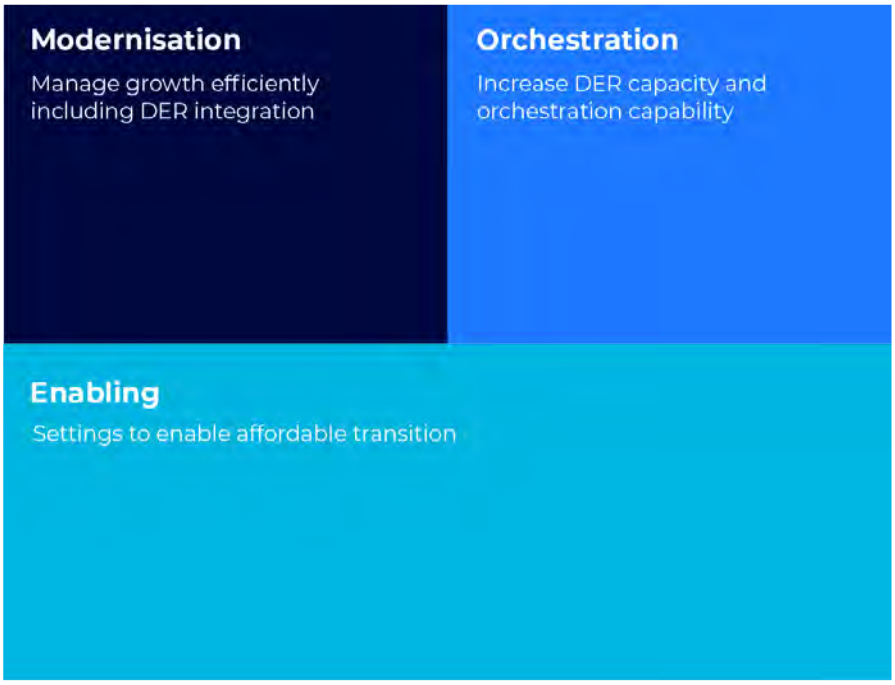

FIGURE 2.2 FUTURE NETWORK ROADMAP (FNR) PATHWAYS

Each pathway consists of several *Planks* that provide the detailed framework for the new capabilities required under each Pathway (refer Figure 2-3) across multi-year time horizons – Foundational (the next 5 years), Embed (5-10 years from now), Scale (10+ years from now).

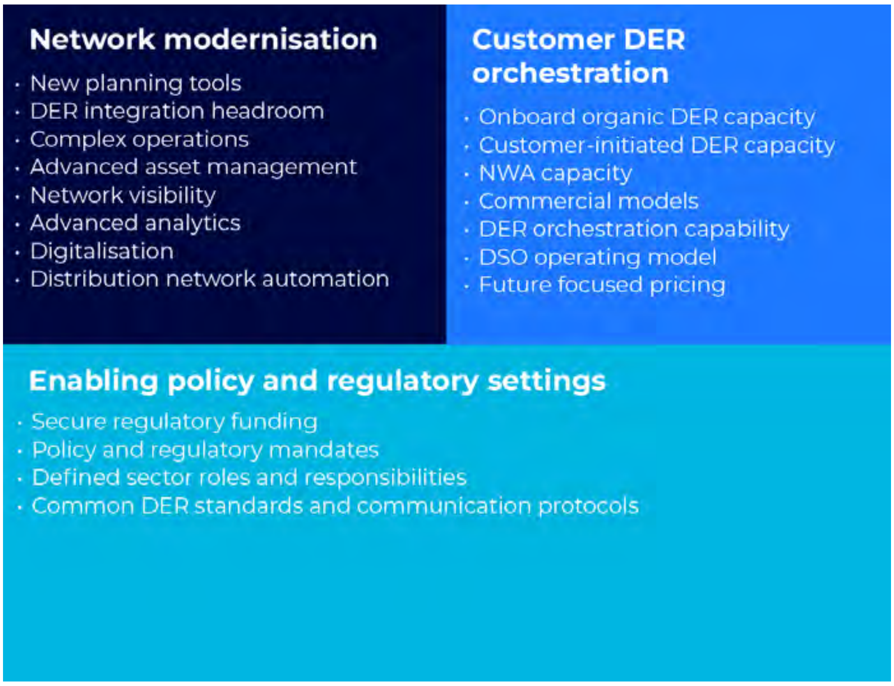

FIGURE 2.3: FNR PLANKS AND PATHWAYS

2.3.3 FUTURE NETWORK ROADMAP FOR THIS AMP CYCLE

The Symphony outcome within this AMP cycle is shown in Figure 2.4. The shaded area between the dark blue line (Symphony) and the light blue line (Pop) reflects our goal for peak load under management with DER orchestration, whether through coordination with third parties or direct control. The goal is 25MW at a whole of network level in 2027 and 200MW in 2032.

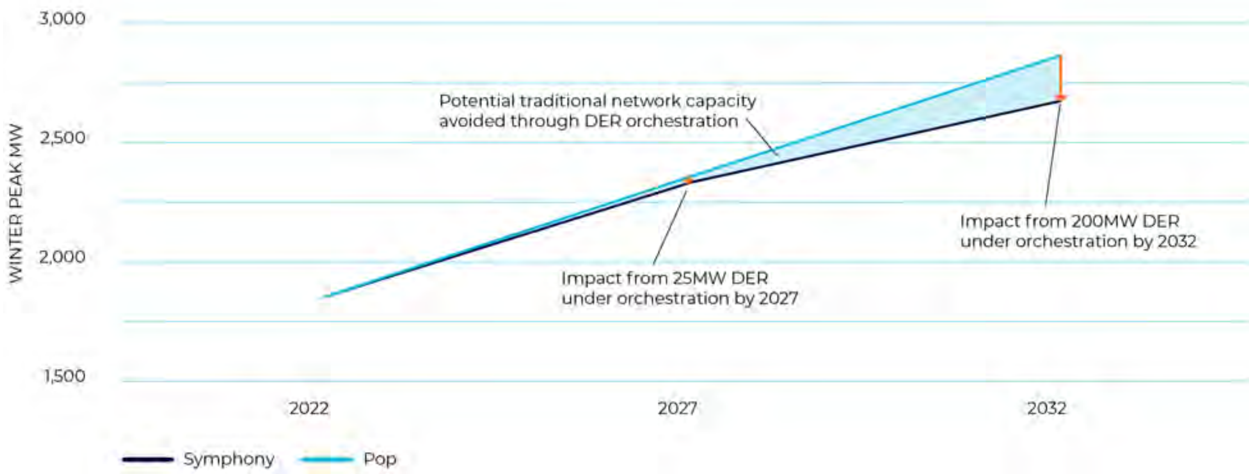

FIGURE 2.4: SYMPHONY GOAL FOR PEAK LOAD ORCHESTRATION FOR THIS AMP PERIOD

To achieve the Symphony objectives, the key priority areas for this AMP cycle **include increasing our access to DER capacity, building capability** for the management and orchestration of DERs and **achieving supportive regulatory and policy settings**.

- **Increasing our access to DER capacity** – through improved visibility of DERs and coordination with third parties and directly integrating DERs with our network management systems.
- **Building capability** – by making no regrets investments in new enabling technologies, continuing to develop commercial arrangements, and understanding the consumer response to load management practices during the first 5 years in preparation for more rapid addition of managed load after year 5.
- **Achieving supportive regulatory and policy settings** - during the first 5 years of this AMP period we will work together with regulators, policy makers, and appliance/network standards agencies to ensure that the regulatory settings enable the orchestration of DERs prior to years 6-10 of this AMP period, where we expect more rapid addition of managed load.

2.3.4 DER CAPACITY

During the period of this AMP we will make a significant effort to increase access to DER capacity:

- Signposting the areas that we have identified as best suited to non-network solutions in the AMP to create opportunities for accelerating the growth of managed load in those areas.
- Secure customer buy-in through education and demonstration projects and continue to learn through demonstration projects.
- Continue to develop digital platforms and data management systems.
- Continue to make adequate investment to maintain network security and resilience in the face of climate disruption.

New DER capacity (managed load) is expected to come from the following categories of load growth:

Organic growth – that is untargeted load from new managed hot water and managed EV charging – including, in both categories, capacity rolled out by retailers and other flex traders. Organic managed load will therefore likely appear dispersed throughout our network. To increase our access to managed load resulting from organic growth during this AMP cycle we will continue our focus on:

- Smart water heating demonstration projects with hot water cylinders on customer premises to validate the use of DER orchestration for constraint management and peak load avoidance/deferral.
- Ongoing implementation and refinement of time-of-use pricing that encourages retailers to work with consumers (and their DER) to proactively shift load out of peak periods.
- Utilising dynamic operating envelopes (DOEs) and other tools to orchestrate smart water heating and EV charging via 3rd party DER managers (e.g. metering/charging equipment providers, retailers, aggregators) to switch and/or throttle DERs. A key aspect of the DOEs that will be developed as part of these demonstration projects, is bringing back the load without causing secondary or unintended network peaks or violating power quality constraints.
- Continuously monitoring where manageable organic load emerges on our network to identify clusters that naturally coincide with our network investment needs.

Customer-driven growth – that is projects where commercial customers actively pursue options for load management at their sites to optimise their connection costs and ongoing energy costs. To increase our access to managed load resulting from customer-driven projects during this AMP cycle we will continue our focus on:

- Commercial agreements with public transport depot customers, implementing Auckland Transport's public transport electrification policy, to reduce customer connection costs and line charges and reduce load growth during peak through the implementation of DOEs via on-premises DER managers.
- Exploring partnerships with private/public electric vehicle charging infrastructure providers providing rapid charging hubs across Auckland, to reduce customer connection costs and line charges to reduce point load growth during peak periods. This will be accomplished through the implementation of DOEs via third party DER managers (e.g. retailers and other flexibility suppliers), or directly to customer-owned rapid chargers.
- Exploring opportunities with customers to reduce customer connection costs and line charges where they are able to reduce ICP-based load growth during peak. This includes private transportation charging infrastructure providers (business carparks, residential apartment block carparks, etc.) operators and customers utilising different types of load management behind the meter (refrigeration, HVAC, battery storage, etc.). This will be accomplished through the implementation of DOEs via third party DER managers, or directly with Vector as the DER manager.

Signposted growth – that is growth in areas that we believe are best suited to deployment of non-network alternatives (solutions that enable "traditional" network projects to be deferred and the CAPEX profile optimised accordingly). To accelerate the growth of managed load in signposted areas in this AMP cycle, we will continue our focus on:

- Implementing the candidate assessment criteria that were developed with the learnings from the recent Warkworth RFP.
- Developing a process to engage on new signpost opportunities with customers, stakeholders, and third parties.
- Publishing interactive online maps to visualize where the network is growing.

More information on the process for signposting projects, the best opportunities and the interactive maps can be found in Section 10.5 and the case study on interactive maps in Section 10.

2.3.5 CAPABILITY

This AMP period will see a significant effort to strengthen and develop internal capability to support the practical deployment of DER capacity, and orchestration of DERs through third parties and directly. At a high level, it includes the following key focus areas:

- Development of dynamic operating envelopes (DOEs)
- Practical deployment of third-party DER orchestration, including through advanced pricing incentives
- Customer experience initiatives to onboard DERs
- Network modernisation to enable whole of system planning, DER integration, DER detection
- Visibility of the low voltage network, including distribution transformer visibility and DER visibility
- Enabling digital systems, integration protocols, cyber security, and new data platforms
- Development and implementation of smart meter data use cases for LV visibility
- Distribution system operator (DSO) capabilities
- Industry collaboration, operating protocols, and common industry standards

- Ongoing development of our DER tariff
- Further development and refinement of cost-reflective pricing

CASE STUDY 1: KEY ENABLERS FOR DER ORCHESTRATION

A key enabler for EV charger orchestration is the publication, following consultation, of Vector's revised Network Connection Standard (ESA002). This standard stipulates the following key requirements for EV chargers on the Auckland network:

- Comply with industry communication protocol (SNZ PAS 6011:2021 & SNZ PAS 6011:2021), which includes the OCPP communication standard;
- A copy of the Certificate of Completion (CoC) for installations of 7kW EV chargers shall be sent to EVinfo.applications@vector.co.nz;
- Bidirectional chargers (for V2G) must comply with AS/NZS 4777.2:2020 and Vector's distributed power generation requirements, which includes lodging a formal application in accordance with Part 6 of the Code and
- Reference to new DERMS connection standard (See chapter 10.3.5)

A key enabler for hot water DER orchestration is the publication, following consultation, of Vector's revised Network Connection Standard (ESA002) in conjunction with the Smart Metering Guideline (EGP503) in the 1st quarter of 2023. These documents stipulate the following key requirements for water heating on the Auckland network:

- Electric-water heaters greater than 50L/1.2kW capacity should be wired into a dedicated channel of the smart meter;
- A pilot wire is to be installed between switchboard and meter board; and
- All smart meters need to have internal load control capabilities.

2.3.6 ENABLING REGULATORY, MARKET AND GOVERNMENT POLICY

A big focus on enabling regulatory, market and policy settings to provide confidence that consumers' flexible demand will be shifted outside peak periods with sufficient certainty to defer investment, especially when under management of third parties.

2.4 Innovation to enable network of the future

Vector has been partnering with other distributors, retailers, and our own customers to promote DER integration and build the knowledge needed for an efficient and effective transformation of our network.

We redesigned our scenario modelling capabilities to be built up from the Auckland Granular Customer model rather than top down (i.e. flipping planning to bottom up), and we are using it to inform our future planning processes (see Section 10.4 for more information).

We have explored different mechanisms for utilising non-network solutions including Ngati Whatua battery-solar community project, SunGenie residential solar-battery deployments, new methods of hot water load control (see case study in Section 10), a peak time rebate trial, deployment of the first grid-scale batteries in NZ, deployment of grid scale battery and standby generation microgrids, behavioural smart EV charging trials (see case study in Section 10.3.5) and NZ's first EV charging network to promote EV adoption (Including V2G).

Additionally, Vector has been deploying digital tools in collaboration with international expert partners to navigate the transition to a digital energy future such as cyber-physical security solutions, smart meter edge data analytics in collaboration with AWS, a Distributed Energy Resource Management System (DERMS) (see Section 10) in collaboration with mPrest, a new Advanced Distribution Management System (ADMS), and the Tapestry collaboration with Google's X, the moonshot factory (see case study in Section 10).

We have connected the first E-Bus depot flexible commercial customer (see case study in Section 10) and will be deploying this solution across a number of customers in this AMP period.

Whereas the focus to date has been on customer behaviour, technology and digital innovation, we are now leveraging this knowledge while we focus on network visibility, DER integration/orchestration, flexibility and system innovation.

CASE STUDY 2: SMART METER DATA INNOVATION FOR NETWORK VISIBILITY

The transition to renewable energy sources is expected to result in electricity displacing fossil fuel-based services, increasing demand on the network.

We anticipate a significant increase in the number of Distributed Energy Resources (DER) that will connect to the network and is already observing the beginnings of these trends.

DER include small scale solar PV (i.e. residential PV systems), battery energy storage systems, hot water cylinders and electric vehicles.

DER will primarily connect to the LV network and are expected to result in changes to peak demand, consumption, timing of electricity use and power flows. We currently do not have adequate visibility of the LV network so is not well positioned to proactivity manage the impacts of increasing DER on network capacity and quality of supply.

Visibility of the LV network means having sufficient recent data (preferably near to real time) to understand the power flows and power quality metrics, the ratings of the network assets and protection settings. Combined, these factors will enable Vector to manage the network effectively and make prudent investment decisions. We have identified that obtaining access to smart meter data as the most efficient approach to gathering the necessary data to provide visibility of the LV network.

We own the data related to network assets and protection settings, however, network usage data is primarily obtained from smart meters which are owned by the Metering Equipment Providers (MEPs) and Electricity Retailers.

To address the existing limitations in obtaining access to the LV network usage data, Vector has developed an Innovation Project that is aimed at developing a new set of processes, that will provide ongoing reliable access to near real-time smart meter data. The project will also establish a platform that will facilitate the analysis and use of the data for strategic and operational decision making.

The types of data required are:

- Interval consumption data is recorded as peak demand (kW)and consumption (kWh) during a given time period. This data is currently recorded by the smart meters and is available from either MEPs or Retailers and enables detailed analysis of the network demand at a more granular level than is currently possible.
- Network Operational Data Services (NODS) provides information on the power quality (including voltage, current, phase and frequency) and event data (such as outages).
- On-demand meter data refers to contacting specific meters to extract data for specific time periods. The data obtained will be the same as interval consumption data and NODS. This is a functionality that will enable targeted data gathering by Vector for investigating specific network events.
- Device data sourced from third parties such as real-time even data from (privately owned) devices at customer's property such as Chorus' Optical network Terminal (ONT). This would provide supplementary data that for LV network visibility and understanding of network events.

Specific use cases that will be enabled by the access to smart meter data include:

- ICP connectivity: ICP-transformer and ICP-phase mapping to enhance connectivity model
- Transformer loading: Transformer, LV Feeder and LV Phase loading visibility for network planning
- New customer connections: New connections based on visibility of transformer loading (no loggers)
- DER hosting capacity: Visibility of transformer voltage and loading headroom to increase DER hosting capacity
- Customer outage visibility: Visibility of outages at individual ICP level
- DER identification: Visibility of unregistered DERs
- Customer and market analysis: Visibility of consumption to enable insights
- Public safety: High impedance fault detection to improve safety
- Load control: Targeted load control using calendar function to manage peak demand

SECTION 03

Network overview

3 – Network overview

3.1 Our network

Vector is the largest distributor of electricity in New Zealand, managing a rapidly expanding energy distribution network across the Auckland region, serving approximately 30 per cent of the NZ population, and representing one-third of the nation's gross domestic product (GDP).

The Vector network area is centred on the Auckland isthmus, supplying 600,112 [1] ICPs between Mangawhai Heads in the north and Papakura in the south, including Waiheke Island in the Hauraki Gulf. Our network is the largest of the electricity distribution businesses in New Zealand in terms of connected customers, peak demand and energy consumption.

The geographical area map in Figure 3-1 shows the GXPs for the entire Vector network area (both the Northern and Auckland network regions) and their supply area boundaries. Neighbouring distribution networks operated by Northpower to the North and Counties Energy to the South can be seen in the figure. Table 3-1 provides a summary of the key network statistics of the Auckland and Northern regions as of 31 March 2022. In addition, Vector supplies a large customer at Lichfield (South Waikato) which is a stand-alone supply directly from a Transpower GXP (not shown in the figure below).

FIGURE 3.1: VECTOR NETWORK GEOGRAPHICAL AREA

[1] Number of electricity connections (2022 Annual Report)

MEASURE	AUCKLAND	NORTHERN	VECTOR TOTAL
Customer Connections [1]	351,792	241,648	593,440
Overhead circuit network length (km)	2,838	5,398	8,236
Underground circuit network length (km)	6,723	4,321	11,044
Grid Exit Points (GXP)	8	6	14
Zone substations (zone substation)	58	55	113
Peak Demand (MW) [2]	1,138	727	1,807
Energy throughput (GWh)	5,558	2,817	8,375

TABLE 3-1: KEY NETWORK STATISTICS (YEAR ENDED 31 MARCH 2022)

3.2 Grid exit points

Vector takes supply from the Transpower grid at 110 kV, 33 kV and 22 kV at 15 points of supply [3] known as grid exit points (GXPs). Transpower owns and maintains the GXP equipment but provides current transformers in their switchgear for Vector's protection schemes. Vector owns the line differential unit protection schemes. Because unit protection consists of protection relays at the GXP as well as the remote ZSS ends, it makes practical sense for ownership by the distributor.

Transpower owns the feeder management relays at the GXPs. The feeder management relays provide backup protection to plant but as their name implies are also used by Transpower to control their circuit breakers. At certain GXPs, most of the subtransmission network switching is required by Vector and under agreement with Transpower, Vector has been enabled to control the subtransmission circuit breakers. Where this operational mode has been agreed the communications schemes between Transpower and Vector have been modified to allow this mode of operation by Vector.

3.3 Network configuration

From the grid exit points power is distributed across Auckland to our zone substations via our subtransmission network. The supply is then stepped down through our zone substation transformers and distributed across zone substation supply areas at 11 kV and 22 kV. The supply is stepped down further to 230 V single phase or 400 V three-phase via our overhead and underground distribution transformers and supplied to our customers through our low voltage (LV) network.

We have lines and cables operating in three distinct voltage ranges:

- Subtransmission – predominantly 33 kV but also 22 kV and 110 kV
- Distribution – predominantly 11 kV but also 22 kV
- Low Voltage (LV) – 230 V single phase or 400 V three-phase. Customers use this network to obtain electricity but also to export when excess electricity is generated by customer owned distributed energy resources

We complement our lines and cables with a range of Distributed Energy Resources:

- 419 Residential Solar and Tesla battery energy systems
- 215 Residential Tesla battery systems (Powerwalls)
- Two diesel powered emergency generating stations at the far end of two lengthy rural networks (Piha and South Head)
- Seven battery energy supply systems (BESS) are in place across the network ranging in size from 1 MW to 2.5 MW to shave peak demand and provide voltage support. Some can operate in a microgrid configuration and have been specifically designed for that operational mode

The table below gives salient details of our investment in BESS systems.

LOCATION	RATINGS	REGION
Zone Substation Glen Innes	1.0 MW / 2.3 MWh	Auckland
Zone Substation Snells Beach	2.5 MW / 6 MWh	Auckland
22 kV Feeder - Vector Lights	0.25 MW/0.475 MWh	Auckland (Harbour Bridge)
11 kV Feeder - Kawakawa Bay	1 MW / 1.7 MWh	Auckland
Zone Substation Hobsonville Point	1 MW/2.0 MWh	Auckland
Zone Substation Warkworth South	2.0 MW / 4.8 MWh	Northern
11 kV Feeder - Tapora	1.14 MW / 1.254 MWh	Northern

TABLE 3-2: BESS SYSTEMS SUMMARY

[1] Average number of customer connections for disclosure year 2022.

[2] Peak demand in each network region occurs at different times of the day and therefore the coincident Vector total peak demand will not directly equate to the sum of the two distinct regions.

[3] 14 GXPs in Auckland and Northern networks combined plus 1 GXP at Lichfield equals a total of 15 GXPs

3.4 Auckland region

3.4.1 OVERVIEW

Eight GXPs supply 58 zone substations in the Auckland network at connection voltages of 110 kV, 33 kV and 22 kV. The Auckland region can be broken down into three primary zones:

- Central business district (Primarily Hobson GXP but certain parts supplied from Penrose GXP)
- Central Zone (Roskill GXP and Penrose GXP)
- Southern Zone (Mangere, Wiri, Otahuhu, Pakuranga and Takanini GXPs)

The Auckland region consists of residential and commercial developments around the urban areas on the isthmus, concentrated commercial developments in the CBD, industrial developments around Rosebank, Penrose and Wiri areas, and rural residential and farming communities in the eastern rural areas.

3.4.2 CENTRAL BUSINESS DISTRICT (PENROSE AND HOBSON GXPS)

The Auckland CBD is supplied from an extensive substation complex in lower Hobson St in the CBD that also contains a 220 kV GXP with 220 kV switchgear and a 220 kV/110 kV interconnecting transformer. The zone substation has 110 kV, 22 kV and 11 kV distribution nodes. The North Auckland and Northern (NAaN) cable from the Transpower Penrose 220 kV node runs through the Hobson GXP 220 kV node and then northwards to Wairau GXP and from there to Albany GXP. Hobson ZSS 110 kV node connects to the 220 kV/110 kV interconnecting transformer via a 110 kV switchboard at Hobson zone substation.

Two 110 kV feeders via the Vector tunnel from Penrose GXP connect to a 110 kV switchboard at Liverpool zone substation. The Hobson zone substation and Liverpool zone substation 110 kV switchboards are interconnected by two 110 kV cables that provide security of supply to each other.

Two 110 kV cables exist from the Hobson 110 kV board and Liverpool 110 kV board respectively to Quay St zone substation. Between Hobson, Liverpool, and Quay bulk supply substations, they supply eight zone substations. To meet growing demand, the distribution network in the CBD is progressively being converted from 11 kV to 22 kV.

3.4.3 CENTRAL ZONE (ROSKILL AND PENROSE GXP)

The central zone is supplied from Roskill and Penrose GXPs. Roskill GXP has a 110 kV node and a 22 kV node. From the Roskill 110 kV node two Vector owned 110 kV underground cables connect to two 110 kV/22 kV transformers at Kingsland zone substation. From the Vector 22 kV node at Kingsland, three zone substations are supplied namely, Chevalier, Kingsland itself and Ponsonby.

The Mt Roskill GXP 22 kV node supplies six zone substations, namely Avondale, Hillsborough, Mt Albert, Sandringham, Balmoral and White Swan as well as the Waterview tunnel. The customer base in these areas is largely residential, with industrial customers in the White Swan area. Kingsland, Mt Albert, and Chevalier are undergoing extensive urbanisation with many high-rise apartments being constructed and planned. A number of areas especially around train stations, have been identified in the Auckland Unitary Plan for high-rise intensification that will further drive load demand.

Penrose GXP has a 33 kV node and 22 kV node. Thirteen zone substations are supplied at 33 kV and two are supplied at 22 kV. The customer base in this area is a mix of residential, commercial, and industrial. The industrial customer base in the Penrose area includes some large industrial customers. It is Vector's largest planning area by demand.

3.4.4 SOUTHERN ZONE (MANGERE, WIRI, OTAHUHU, PAKURANGA AND TAKANINI GXPS)

Five GXPs cover the Southern zone namely Mangere, Wiri, Otahuhu, Pakuranga and Takanini GXPs. Vector takes supply from the listed GXPs at 33 kV except Otahuhu where the grid supply voltage is 22 kV.

Mangere GXP covers the Mangere township and surrounding residential commercial and industrial areas, extending south to the continuously developing commercial areas surrounding the Auckland airport. This supply area includes large logistics centres.

Pakuranga GXP area covers East Tamaki, Pakuranga and Howick and the growth area of Flat Bush to the south. The customer base in these areas is largely residential, with industrial customers in East Tamaki and Greenmount.

Wiri GXP covers the established areas of Manukau, west to the Wiri commercial area and south to the residential area of Clendon. The customer base in this area is a mix of residential, commercial, and industrial.

Takanini GXP covers the urban areas of Manurewa, Takanini, and Papakura township, extending east to the more remote areas of Clendon, Maraetai, Beachlands, as well as Waiheke Island. The customer base in this area is a mix of mostly residential, with some light commercial and industrial.

Otahuhu GXP covers the Highbrook commercial and industrial area, and the Otara and Bairds areas. The customer base in this area is mainly industrial with some interspersed residential areas.

3.5 Northern region

3.5.1 OVERVIEW

Our network in the Northern region has 55 zone substations which supply a mix of both urban and rural areas. These zone substations are supplied from six GXPs all at a supply voltage of 33 kV. The Northern region can be broken down into three primary zones:

- Albany and Wairau GXPs
- Henderson and Hepburn GXPs
- Silverdale and Wellsford GXPs

The Northern region consists of residential and commercial areas in the southern reaches of the region, light industrial and commercial developments in the Wairau Valley and around the Albany Basin, and rapidly developing urban areas in the Silverdale and Wellsford GXP supply areas. Further north the area has extensive and intensive farming activities

3.5.2 ALBANY AND WAIRAU-ALBANY [1] GXP

Thirteen zone substations are supplied at 33 kV from Albany GXP. The Albany supply area includes Albany, North Harbour, Rosedale, Forest Hill, Browns Bay, the East Coast beach enclaves as well as Torbay and Greenhithe. The customer base in this area is predominantly residential but extensive commercial areas exist in Albany and in the Wairau Valley. Extensive and rapid urban infill developments permitted under the Unitary Plan together with large datacentres, are driving load growth in the Albany supply area.

Wairau zone substation is supplied via a 220 kV/ 33 kV interconnecting transformer from the GXP that is co-located at Wairau zone substation. Three 110 kV lines from the Albany GXP 110 kV node connect directly to three 110 kV/ 33 kV transformers at Wairau zone substation. The Wairau zone substation supply area includes Wairau Valley, Glenfield, Devonport, Bayswater, Takapuna, Northcote, Birkenhead, and Beach Haven. The customer base in this area is largely residential but many commercial customers exist in the Wairau Valley, Takapuna, and Highbury areas.

3.5.3 HENDERSON AND HEPBURN GXP

Vector takes supply from the Henderson 33 kV bus via two 220 kV/33 kV transformers. Ten zone substations are supplied from this GXP. The supply area covers Ranui, Swanson, Woodford, Hobsonville including Hobsonville Point, Westgate, Te Atatu, Riverhead, Greenhithe and Simpson Rd. The Henderson area is one of the major growth areas in the Auckland region with major residential greenfields developments at Hobsonville Point as well as in Whenuapai, Riverhead, Kumeu, Westgate and Red Hills to the west. The customer base in the Henderson area is largely residential but the Westgate commercial area is rapidly expanding with logistics centres and large datacentres. This is driving load demand.

Vector takes supply from the Hepburn 33 kV bus via three 110 kV/33 kV transformers. Ten zone substations are supplied from this GXP 33 kV node. The Hepburn supply area includes Rosebank, Green Bay, Ranui, Oratia, Glendene, New Lynn, Titirangi extending westward out to the coast including Laingholm and the beach enclaves south of Laingholm. The customer base in this area is largely residential with commercial customers mainly in the Henderson township and industrial customers in Rosebank.

3.5.4 SILVERDALE AND WELLSFORD GXP

Vector takes supply from the Silverdale 33 kV GXP bus via two 220 kV/33 kV interconnecting transformers at this GXP. Eight zone substations are supplied from this 33 kV GXP node. The Silverdale GXP supply area stretches from Albany in the south to Waiwera in the north and stretches west to Helensville and, all the way to the West coast including South Head.

It covers the greater Orewa emerging city area, Silverdale, and Millwater urban areas as well as the area east of SH1 that comprises Whangaparaoa, Stillwater, Red Beach, Manly, Tindalls Beach all the way to Gulf Harbour. The customer base in this area is largely residential but the Millwater commercial area is rapidly developing and includes new large-scale datacentres, warehouses, and logistics centres. Urban infill permitted under the Unitary Plan is also having an impact on load growth.

The Wellsford area is the most northern in Vector's network. It stretches from Wellsford to Warkworth and includes the townships of Matakana, Sandspit, Omaha and Snells Beach, Leigh in the south and east and the Tapora isthmus in the west. In the North the network stretches to Te Arai and Tomarata. Wellsford GXP supplies three zone substations: Wellsford, Warkworth and Snells Beach via two 110 kV/33 kV transformers. A fourth zone substation is under construction at Big Omaha and a zone substation is planned at Sandspit.

Wellsford and Warkworth zone substations are undergoing extensive refurbishments with complete modernisation of the subtransmission switchgear and installation of an additional subtransmission circuit to Warkworth ZSS to make it ready for the modelled peak demand. The customer base consists of urban customers in the larger townships of Wellsford and Matakana, both rapidly expanding, as well as beach enclaves such as Omaha and Snells Beach that are both expanding and are becoming sought after areas for expansion and development. The Wellsford supply area also includes a large rural network that contains the lengthiest 11 kV overhead distribution circuits in Vector's network. The customer base in this area is largely residential with some commercial customers. Some of the farming customers are extensive operations with high load demands. The Tapora isthmus is equipped with a large-scale battery energy system that can operate in islanded microgrid mode. This battery energy system has proved to be crucial for the continued operations of avocado farming operations during network contingencies.

[1] The reason for the use of the term Wairau-Albany GXP is because the Wairau zone substation has a 220 kV/ 33 kV GXP connection via the GXP at Wairau zone substation as well as three 110 kV overhead line supplies from a 110 kV GXP node at Albany GXP

3.6 Asset overview

This section provides an overview of the asset portfolio that Vector owns and operates including the overall population of our key assets.

3.6.1 ASSET HEADER CLASSES

The asset portfolio owned by Vector is divided into nine asset classes. For each asset class, a strategy document records the asset strategy down to sub-asset class level.

- EEA 100 Subtransmission Switchgear
- EEA 200 Power Transformers
- EEA 300 11 kV – 110 kV Cable Systems
- EEA 400 Overhead Lines
- EEA 500 Distribution Equipment
- EEA 600 Auxiliary Systems
- EEA 700 Infrastructure and Facilities
- EEA 800 Protection and Control
- EEA 900 Distributed Energy Systems

3.6.2 ASSET POPULATIONS

The table below provides an overview of our asset population across our electricity network for the Auckland and Northern regions combined.

ASSET TYPE	POPULATION
Subtransmission Switchgear	
Indoor switches	1,629
Outdoor switches	101
Power Transformers	
Power transformers	221
11 kV – 110 kV Cable Systems	
Subtransmission (km)	608
Distribution (km)	3,898
Overhead Lines	
Subtransmission (km)	390
Distribution (km)	3,707
LV overhead lines (km)	4,092
Poles	125,487
Distribution Equipment	
Transformers	22,654
Switches	21,647
LV cables (km)	6,100
Infrastructure and Facilities	
Buildings (including customer substation buildings)	245
Protection and Control	
Protection relays	3,272
Generation and Energy Storage	
Utility Battery Energy Storage Systems	7

TABLE 3-3: ASSET POPULATION SUMMARY

SECTION 04

Customers and stakeholders

4 – Customers & Stakeholders

4.1 Customers – beyond the bill payer

As an electricity distribution business (EDB) Vector is responsible for transporting power (received from the national grid) to most of the homes and businesses across the Auckland region. While Vector is responsible for connecting new consumers to the network, maintaining supply to consumers and in particular, restoring supply after interruptions, we do not contract directly with end users. The only exception is a handful of commercial and industrial consumers that have dedicated capacity or non-standard supplies.

Instead, Vector has default distributor agreements (DDA) with energy retailers. The retailer contracts with the consumer and bundles all the associated generation, transmission, distribution, retail and other charges and levies together, which are then repackaged and on-sold, potentially with other utility services, via a retail offering. Vector's relationship with the end user is known as an 'interposed' one.

Auckland is New Zealand's largest urban centre making up approximately 33% percent of the NZ population. The region is the economic powerhouse of the country providing 38% of the nation's annual gross domestic product (GDP). We deeply understand the criticality of the electricity network to the lives of Aucklanders and the prosperity of New Zealand. For us to be able to build, operate and maintain a modern, reliable, and affordable network that can support New Zealand's energy transition and decarbonisation goals, we must first understand the needs, values and expectations of the people who ultimately use and rely on electricity. It is for this reason that we do not simply focus on the few entities that contract with us. We instead look to the 1.7m people in the Auckland region supplied across 600,112 connection points, all of whom we consider a 'customer'.

In this Asset Management Plan the term 'customer' is used in this broader context.

4.2 Customer as a key strategic pillar

Vector's Symphony strategy is about putting the customer at the centre of the energy system and at the heart of our decision-making. This is about more than delivering great customer service. It is about deeply understanding the customers' situations, perceptions and expectations and making them a focal point of all decisions.

The energy transition is occurring at an ever-increasing pace. How electricity is generated, transported, stored, traded, and consumed is rapidly changing and will continue to evolve. These changes are driven by customers. It is their changing behaviours, value sets and choices that are driving and will continue to drive the change.

It has never been more critical to understand and engage with customers to ensure we can help to facilitate an equitable and affordable energy transition that provides customers with the choices that they want.

4.3 Vector's customer centric approach

4.3.1 HOLISTIC & CONNECTED APPROACH

Vector takes a holistic approach to ensure that all its operational and strategic elements are aligned to the customer. Considering all elements as a connected system, ensures that there is a continuous feedback loop between strategy, operational implementation, and performance.

A high-level representation of this is depicted below where key business activities and strategies are shown as connected to core customer elements.

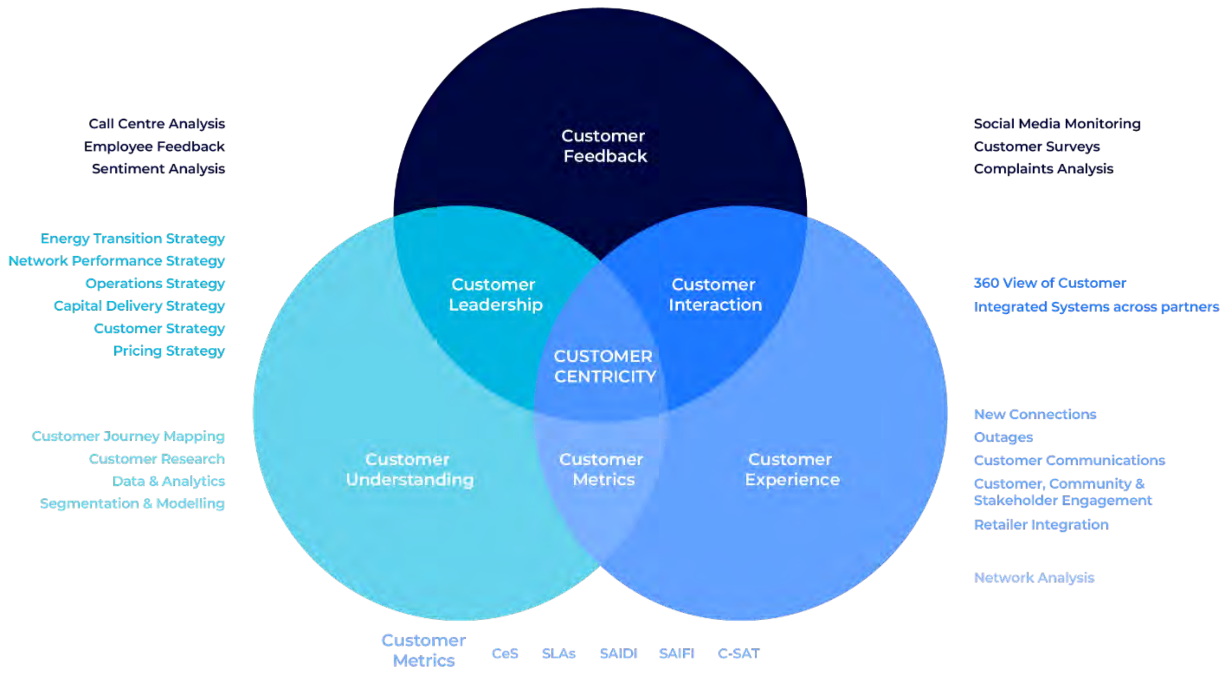

FIGURE 4-1: CUSTOMER CENTRICITY AT VECTOR

4.3.2 DATA FIRST

Vector employs a data first strategy when it comes to understanding our customers. By utilising our data science capabilities (via a specialist energy systems function) and our dedicated Customer Insights team, we can develop deep and clear pictures of customer behaviours, trends, and drivers. This capability is becoming even more important given the increasing complexity of the energy system. It also allows us to extract greater insight from operational and transactional data and reduce the time to action.

Given the scale of our customer base and operations (noting that in Auckland many suburbs are the size of New Zealand towns and small cities) a sophisticated data and analytics capability is necessary to identify correlations, drivers, and other relevant elements to develop our hypothesises and build deeper understanding of what is, and could be happening, at the granular customer level. We can then supplement this where appropriate with targeted qualitative research. This includes methods such as surveys and focus groups which can aid in filling in the gaps as to the 'why'.

Doing targeted qualitative research allows us to directly engage only when necessary, thereby avoiding survey fatigue and engaging on some energy issues that the average layperson may not have the background to understand. It also allows us to focus in on the correct / affected populations and use appropriately targeted questions and language.

4.4 Understanding & engaging with customers

4.4.1 USING DATA

Vector's Insights team is tasked with continuously analysing industry and customer data to support the development and implementation of core operational and investment strategies. Some recent examples of the types of output that have been produced are outlined below:

Example 1: Pricing Development – Identifying Customer Level Impacts

When Vector looks to optimise or amend pricing tariffs or structures, a key element is ensuring that we understand the impacts on customers before any decisions are made. In order to do this, we are increasingly using interactive data exploration tools to investigate trends, clusters, and anomalies in large data sets.

For recent pricing changes, we calculated the impact of the proposed changes for residential customers for whom data was available (which was approximately 75%). We did this calculation at the customer level and were able to visualise and analyse the outcomes across multiple parameters and views. Figure 4.2 shows our detailed approach to inspecting how proposed pricing changes impact residential customers across deprivation deciles. This type of chart shows the impact of price changes across the bulk of customers as well as identifying any outliers which can be individually investigated. The benefit of this type of analysis is that the pricing team is able to understand the impacts of pricing changes during development to ensure, for example, that changes do not unfairly or unexpectedly affect different customer groups.

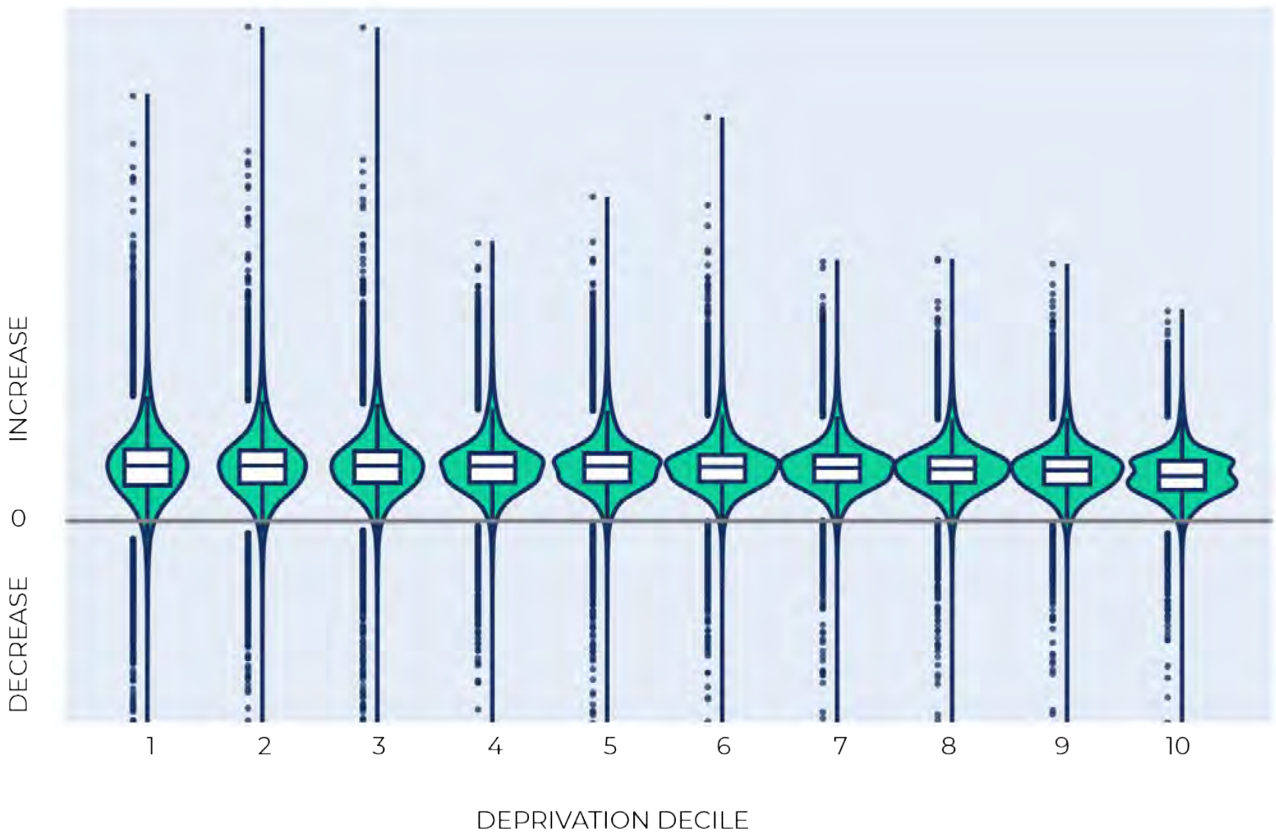

FIGURE 4-2: ANNUAL CUSTOMER BILL CHANGE BY DEPRIVATION DECILE

Example of analysis done during pricing development to understand the bill impacts at the customer level when considered with deprivation deciles. The plot shows both the distribution of customers (width of green area) by annual bill change, and the outliers (dots), with the white rectangle in addition indicating the range within the first and third quartiles (50% of customers), and the mean. The example above shows that the impacts of the price changes across deprivation deciles is not materially different. This is just one of the ways that we ensure that our pricing changes do not unintentionally impact different segments or types of customers unfairly.

Example 2: Identifying potentially impactful behaviour trends

With Vector now receiving half hourly data from most retailers, we have been able to update our customer models which up until this point have been reliant on data obtained in 2015. After rerunning the clustering analysis with the updated data for the purpose of identifying residential daily demand profiles, we have seen changes occurring across most profiles when compared to 2015 as well as the emergence of a new night peaking profile. This 'late evening peak' profile has a sharp peak emerging after 9pm. More investigation is required to understand this, however, we are looking to discover the extent this peak is driven by specific retailer offerings, the types of customers this is more prevalent for, where on the network this is a feature and what are the main drivers for this behaviour. The answers to these questions will be an important input into our operational, asset investment and strategic network decisions.

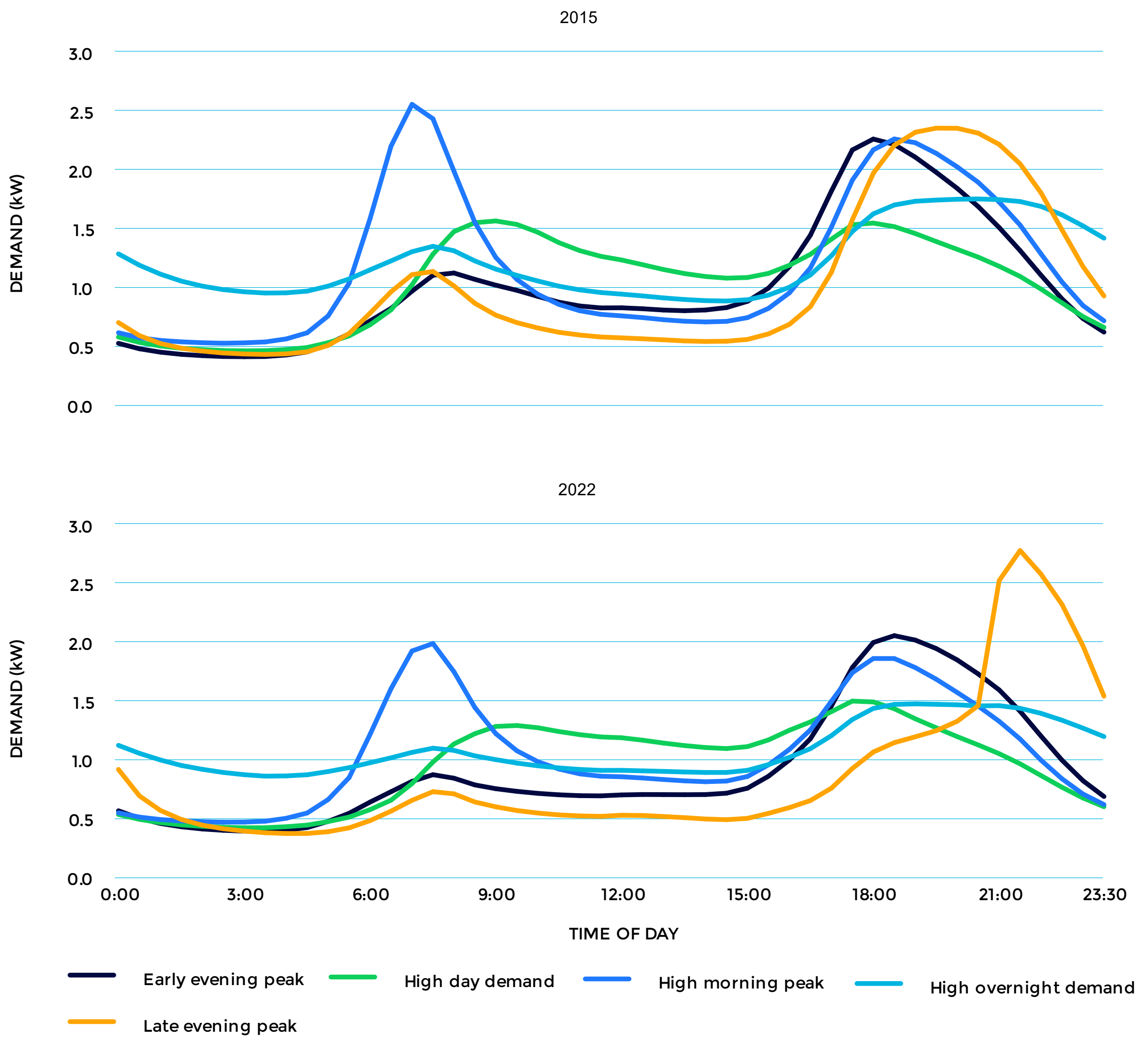

FIGURE 4-3: RESIDENTIAL CUSTOMER ELECTRICITY DEMAND PROFILES FOR 2015 AND 2022.

4.4.2 DIRECT ENGAGEMENT

Vector has a comprehensive Voice of Customer and Engagement Programme covering all customers and key stakeholders. We employ a model adapted from Camorra Research which identifies five core relationship types – see Figure 4.4. Vector has built robust engagement and reporting programmes across all five types represented in the model and is constantly looking to evolve and improve on these utilising its Customer Insights and Customer Excellence teams.

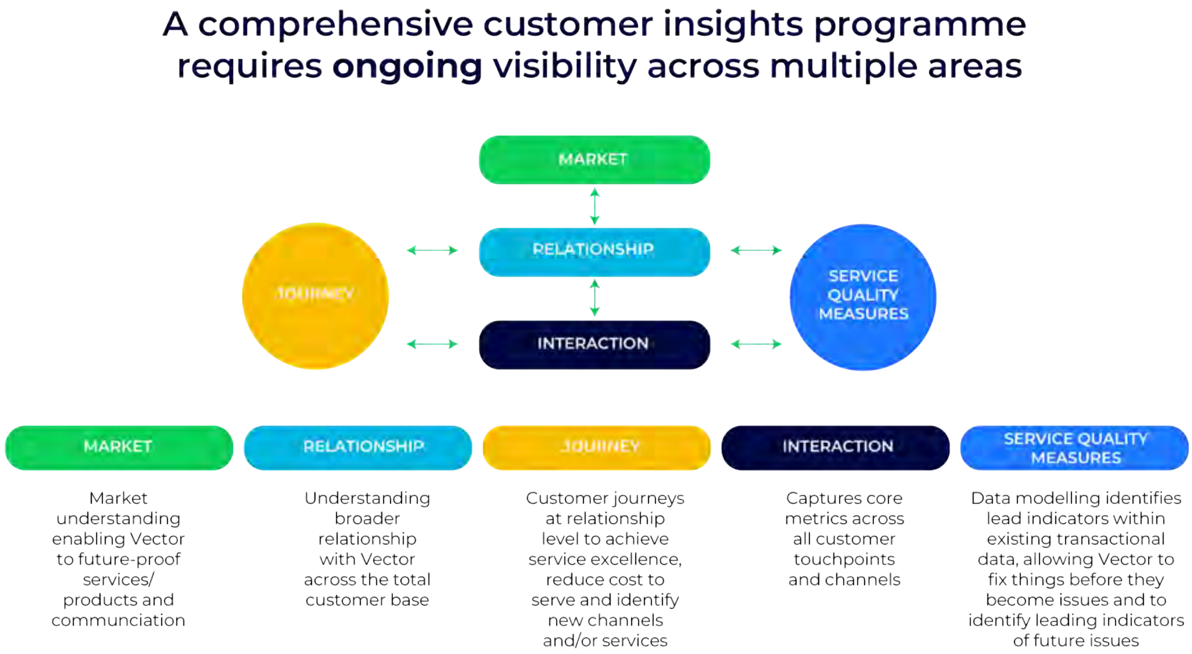

FIGURE 4.4: VECTOR'S CUSTOMER ENGAGEMENT FRAMEWORK – ADAPTED FROM CAMORRA RESEARCH LIMITED

In addition to our Voice of Customer Programme, Vector has a number of dedicated roles which engage directly with customers, retailers, community groups and other stakeholders on a regular basis. Through these direct interactions Vector can keep abreast of what is key to these groups as well as discussing performance and operational matters that are important to them.

4.5 Partnering with our customer and stakeholder groups

An illustrative summary of some of the key customer and stakeholder groups we engage with are shown in Table 4-1.

GROUP	INTEREST AND PRIORITIES	HOW WE ENGAGE
Residential & Small to Medium Commercial customers (~535,000 ICPs)	Reliable and affordable network. Useful, accurate and timely information where outages occur or are required. Multiple channels to access information or lodge requests.	Contact Centre manages phone calls, social media interactions, emails and SMS, for outages and general enquiries Outage Centre is a web-app providing self-service information on planned and unplanned outages Customer Communications team manages proactive notification of planned outages required for maintenance work Regular Voice of Customer Programme including monthly monitors and post storm surveys Customer Advisory Group – cross functional group of senior customer managers and executives focused on driving continual improvement across all things customer. Includes one independent expert member
Corporate and large commercial (~70,000 businesses)	Larger commercial entities make individual decisions around network resilience and configuration to manage their unique requirements. Emerging needs around decarbonisation and electrification of industrial processes.	Key account team provide a point of contact and management for larger designated key account customers
Public EV Charging Companies (emerging customer type)	Network information to help identify cost effective siting of assets. Pricing to reflect new business model Faster turnaround of high volume of requests	Dedicated personnel to have single point of contact / engagement, collaboration & escalation (if required)

GROUP	INTEREST AND PRIORITIES	HOW WE ENGAGE
Developers of large commercial projects	New commercial connections often require bespoke connection plans. Increasing interest in the implications of new technology such as commercial batteries, distributed generation and rapid EV charging	Dedicated team providing individual management of their engagement with Vector quote, design and contract
Developers of residential sub-divisions	Ease, process and cost of new connections to the network Coordination with other utilities Transparency and availability of job progress	Two streams for engagement, including (for projects larger than five lots or greater than 100-amps) a dedicated team arranges the electrical engineering design, commercial terms and pricing for residential subdivisions and developments
Retailers	Maintain strong relationships and ensure ease of doing business Promote customer service Ability to develop and implement new products and services Industry development & coordination	Range of senior managers work with retailers directly as well as participating in engagement with the fora and industry groups associated with retail-orientated and consumer-orientated work and industry development programmes (resource is dependent on issue and expertise required) Commercial activities managed through dedicated senior manager
Infrastructure providers (e.g. road, rail, telcos, water)	Ensuring large infrastructure projects have the greatest possible synergies and cause the least possible disruption for the public (e.g. City Rail Link)	Key account team have direct account management relationships with all major infrastructure operators in the region
Community groups & business associations	Community resilience planning, and investment and affordability	Dedicated Community Engagement Manager Relationship managers spanning community groups, local boards and community media organisations
Iwi	Create and maintain strong working relationships with iwi across Auckland	Dedicated Community Engagement Manager, Resource management & planning lead
Auckland Council and CCOs	Creating enabling infrastructure, electrification of public transport; coordination of operational and investment activities; civil defence and emergency management; sharing of asset location information; climate adaptation	Dedicated Key Account managers; range of senior managers across specific areas such as risk/emergency management, operations, forecasting etc
Transpower	Asset planning and investment; long term forecasting; scenario modelling; operations; future industry developments; pricing	Senior managers engage across specific functions including Planning & Future Networks; Pricing; Commercial; Forecasting; Operations as well as Regulatory and Industry Development
Regulatory Bodies	Foster open and trusting relationships with policymakers and regulatory decisionmakers, engaging in targeted decision-making processes where required, to advocate for robust and sustainable policy and regulation in the long-term interests of consumers	Senior managers engage across specific functions including Policy and Regulatory; Pricing; Future Networks; as well as a range of senior subject matter experts as required

TABLE 4-1: GROUPS AND ENGAGEMENT METHODS

4.5.1 ACCOMMODATING INTERESTS AND MANAGING CONFLICTING INTERESTS

We accommodate our customer and stakeholder interests in our Asset Management Practices by, amongst other things:

- Due consideration of the health, safety and environmental impact of Vector's operations;
- Looking after the health, safety and wellbeing of our employees, their families, and our communities;
- Providing a safe, reliable and resilient distribution network;
- Due consideration for the affordability of our services;
- Quality of supply performance meeting consumers' needs and expectations, subject to trade-off 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;
- Complying with regulatory and legal obligations;
- Looking ahead and planning for future innovation and disruption;
- Removing barriers to innovation;
- Supporting and enabling the uptake of Distributed Energy Resources (such as EVs and solar);

With numerous stakeholders with diverse interests, it may happen that not all stakeholder interests can be accommodated, or conflicting interests exist. From an asset management perspective, these are managed by:

- Clearly identifying and analysing stakeholder conflicts (existing or potential);
- Seeking an acceptable alternative or commercial solution based on a set of fundamental, consistent and transparent principles;
- 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;

In developing solutions where conflicting interests exist, Vector strives to achieve consistency, transparency and fairness.

4.5.2 EXTERNAL ENGAGEMENT AND COORDINATION

Vector regularly engages and exchanges ideas and learnings with other EDBs and research institutions in New Zealand, and with entities from across Australia, Europe, the United States and Japan. These overseas engagements are a valuable addition in that we can focus on jurisdictions that have similar networks to Vector, have already experienced high levels of uptake of impacting technology such as electric vehicles and domestic solar PV installations, have tried different load shedding or incentive programmes, or have introduced different pricing and tariff structures etc. Of particular note is that over the last year Vector has been in active engagement with Florida Light and Power (an entity that experiences large numbers of hurricane events and which has a sophisticated and mature emergency response capability) to identify learnings that Vector can implement. This is of particular importance given climate modelling shows more extreme weather events in New Zealand, and as we have experienced in early 2023.

To ensure Vector is also engaging with the leading institutions looking at the customer driven energy transition, Vector has strong linkages with several New Zealand universities as well as international energy research bodies such as the Institute of Electrical and Electronics Engineers (IEEE), the Energy Systems Integration Group (ESIG) and ReCosting Energy (part of the UK based thinktank Challenging Ideas). Vector is also a participant in these forums having provided international webinars on our Smart EV Charging trial [1] as well as publishing journal articles [2] on our customer modelling approach and outcomes – both of which have generated strong international interest and discussion.

Within Vector there is a continuous drive to place customer at the heart of the business. In 2022 the focus was on strengthening and broadening our Voice of Customer Programme to ensure our operational performance and investments in both system and non-system assets, continued to reflect the needs, expectations and values of those that we supply.

For 2023, our focus is on ensuring robust processes are in place to support and encourage active engagement with key stakeholders and customer groups so we can understand their evolving needs and expectations as the energy transition unfolds. We know that the energy transition will occur at different paces for different parts of the network and for different customer groups. Understanding these different elements will be extremely important for guiding many of the decisions that will need to be made over the next one to two decades.

4.6 What our customer insights programme is telling us

Through our analytics and Voice of Customer Programme Vector gains insight into what matters for customers. Below is a summary of some of the high-level themes developed from our research with examples of how Vector is responding:

THEME	INSIGHT	EXAMPLES OF WHAT VECTOR IS DOING
Over Arching Insights	Customers are sensitive to price increases	• Detailed analytics allows Vector to see the effect of proposed changes on customers across multiple factors including deprivation • Future Network roadmap describes how Vector is developing new capability to increase utilisation of electrical assets and minimise new builds whilst optimising operating costs • Rigorous advocation on behalf of the customer to ensure pass through costs (e.g. transmission and government levies) are fair
Corporate and large commercial (~70,000 businesses)	The energy industry is confusing for most residential customers	• Provision of educational communications and simplified language regarding the industry and what Vector does
Public EV Charging Companies (emerging customer type)	Customers expect utilities to be as good as their best customer experience	• Constantly evolving Voice of Customer Programme and deploying 'insights to action' • Customer Journey mapping with regular effort and satisfaction monitoring across key points • Dedicated user experience team • Engagement with customer teams across industries
Customer Experience	Customers want to interact with Vector through multiple channels	• Deployment of multiple digital channels allowing push and pull communications supported by dedicated locally manned call centre
	Customers place a high value on having access to relevant and timely information	• Outage centre • SMS updates during outages including estimated time to restore • Social media and web updates (text and video) • Media updates and radio ads • Direct access to control room for lifeline utilities
	Commercial customers want more visibility of network asset information	• Publicly available asset maps via internet • We are in the process of working to publish network capacity information which will be overlaid on asset maps

[1] webinars on our Smart EV Charging trial

[2] https://www.sciencedirect.com/science/article/abs/pii/S1040619020301287

THEME	INSIGHT	EXAMPLES OF WHAT VECTOR IS DOING
		• Developing tool to determine LV transformer capacities to speed up connection requests including identifying areas that can support large new loads (e.g. public EV charging)
The Future Network	Customers want to benefit from the investments they make in energy efficiency and energy alternatives	• Working with retailers and other third-party providers to support development of new demand-side products • Engaging with retailers on network pricing and tariff design • Solar PV connection standards
	Customers are prepared to participate in demand programmes where there is no noticeable impact on them and they do not have to actively participate	• Development of new demand side options • Use of customer trials • Coordination with third parties managing customers' demand
	Traditional pricing structures may not be suited for new business models e.g. public EV charging	• Engaging with Public EV charging companies to understand their needs and consider pricing design development
Access & Affordability	Customers support the energy transition and decarbonisation but are concerned about who will pay for this	• Detailed analytics and customer research to understand pricing impacts and tolerance
	Those who own their own homes benefit more from energy efficiency	• We engage with government agencies to make our insights available to them • Participate and support research by universities and other agencies on energy affordability
	Customers want a more reliable network but do not want to pay more	• Symphony strategy is about utilising digital capabilities and creating new energy business models to mitigate the costs of increasing capacity demands from electrification of transportation, population growth and decarbonisation initiatives
	The more vulnerable customer groups are less likely to engage with, or complain to, their energy company	• Dedicated community liaison manager
Network Reliability	Tolerance for planned outages, especially on weekday days, is reducing	• Increased use of new tools such as portable transformers and by-pass cables, utilisation of portable generation
	During a storm event customers appreciate there may be long outages, however, they want early communications to help them prepare	• Storm planning & readiness • Dedicated communications team and social media managers provide regular updates • In field assessors and access to helicopter (for hard to access rural areas) allows quicker on the ground assessments • Connected systems allow updates from field crews to be visible to Vector HQ • Applying learnings from peer EDBs in cyclone-prone areas, such as US-based Florida Light and Power
	Customers in traditionally rural areas that are being intensified are expecting urban service levels	• Publication of service level maps and explanation of these • Community engagement • Service level reviews

TABLE 4-2: CUSTOMER INSIGHT PROGRAMME THEMES

SECTION 05

Asset management systems

5 – Asset management at Vector

This section describes the framework that supports and enables Vector's asset management practice.

Vector's asset management practice is a multi-utility practice that includes electricity, gas and fibre communications assets. Much of the enabling framework applies equally to each of those utility networks, however where a practice at Vector relates specifically to its electricity distribution network it is called out in this section.

5.1 Asset management policy and principles

Vector's corporate vision is to create a new energy future and innovation is at the core of our culture of continuous improvement.

Our Asset Management Policy supports our vision of creating a new energy future by setting clear principles (detailed below) to guide the development of Vector's asset management objectives and plans. Our policy principles represent Vector's values, commitments and strategic pillars which apply to all employees and partners (field services providers, contractors and suppliers), involved in the management of Vector's electricity assets.

ASSET MANAGEMENT PRINCIPLES

1. Safety is our highest priority, and we strive to achieve zero harm to employees, contractors, and the public through the management of our assets over their entire lifecycle.
2. We strive to optimise the total lifecycle costs of our assets in ensuring the safe, reliable, resilient, efficient, and affordable provision of energy related services.
3. We comply with internal policies, processes, and established frameworks as well as applicable statutory and regulatory obligations.
4. We use risk models, data, analytics, and market driven insights to make decisions that are in the long-term interests of our customers.
5. We use innovation to accelerate the convergence of traditional and digital assets to manage and meet our customers' evolving expectations.
6. We manage the impact of our assets on the environment while supporting both Vector and our customers' decarbonisation objectives.
7. We engage commercially but collaboratively with our partners by encouraging open and clear communication to leverage diversity of thinking and experience.
8. We align our Asset Management System with industry recognised asset management practices including ISO 55001.
9. We manage risk effectively, and continuously adjust our approaches to manage new and emerging risks such as cybersecurity, privacy, and climate change.
10. We measure the effectiveness of our efforts to ensure we continuously improve our asset management capabilities in delivering our vision.

TABLE 5-1: VECTOR ASSET MANAGEMENT PRINCIPLES

5.2 Asset management objectives

Our Asset Management Objectives have been developed in alignment with the principles set out in our Asset Management Policy. The objectives further consider our operating environment and represent specific stakeholder requirements.

These are considered at a more detailed and defined level, enabling appropriate asset management plans and activities to be developed and set.

FOCUS AREA	OBJECTIVES	AM POLICY ITEM
Safety, Environment and Network Security	• Prevent harm to workers, contractors and the public through our work practices and assets. • Ensure health and 'safety always' is at the forefront of decision making for the business. • Comply with relevant safety and environmental legislation, regulation and planning requirements. • All staff are competent and trained in their applicable roles with the right equipment available to work safely and effectively. • Asset management activities align with environmentally responsible and sustainable behaviours, in line with industry best practice, enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).	1, 6
Customers and Stakeholders	• Enable customers' future energy and technology choices. • Provide a high-quality customer service experience across all interactions. • Listen to and learn from our customers to ensure our service offering aligns with customer expectations. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times. • Ensure the long-term interest of our customers by providing an affordable and equitable network.	2, 4, 5, 6, 7, 9
Network Performance & Operations	• Comply with regulatory quality standards set out in the DPP3 Determination. • Maintain accurate and comprehensive information management systems to drive continuous improvement of our asset health database and information records and meet regulatory reporting obligations. • Continual improvement of our asset management system and alignment to ISO 55001. • Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact-based investment profiling. • Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with security of supply standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings. • Manage performance of field service providers through effective commercial arrangements and regular review.	2, 3, 4, 5, 7, 8, 9, 10
Future Energy Network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc – operations: transition to distribution system operator model and whole of system planning • Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market.	2, 3, 4, 5, 6, 7, 9, 10

FOCUS AREA	OBJECTIVES	AM POLICY ITEM
	• Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.	

TABLE 5-2: VECTOR ASSET MANAGEMENT OBJECTIVES

5.3 Asset Management Standard

Vector's Asset Management Standard links the organisational asset management objectives to the tactical asset management practice. The Asset Management Standard creates a clear link between Vector's vision, strategic objectives and asset management plans. The framework for our asset management standard is shown in the diagram below.

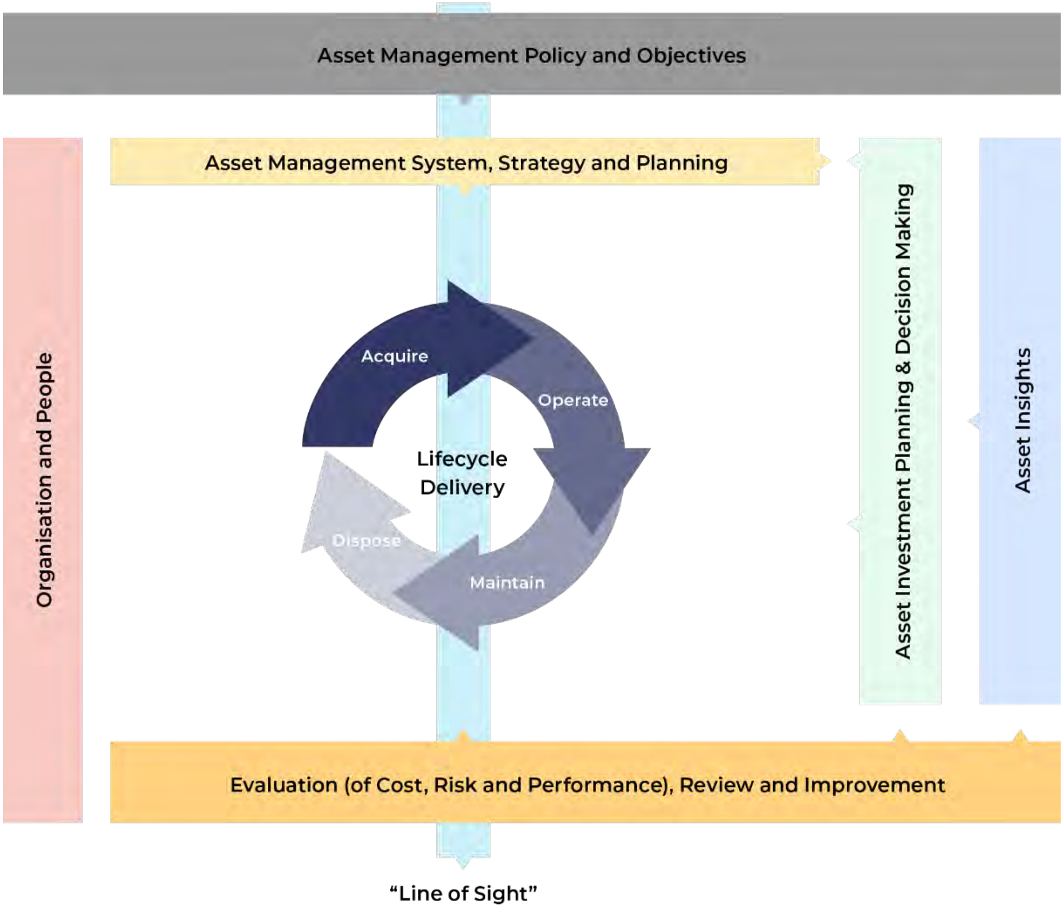

FIGURE 5.1: VECTOR'S ASSET MANAGEMENT STANDARD FRAMEWORK

Continuous improvements in our practices, with supporting cost, risk and performance monitoring, as well as data driven reporting, ensure a full "Line of Sight" throughout the asset management governance structure, from Asset Management Objectives to individual asset level performance. We continuously measure and review progress against Asset Management Objectives to provide assurance and to respond quickly to changes in our operating environment.

Table 5-3 provides an overview of the standards and sub-elements that form the foundation of our asset management standard. Vector is continually advancing its asset management practices to best position ourselves to achieve its objectives and ultimately its vision of a new energy future. This journey includes alignment of our asset management system to ISO 55001.

5.3.1 ASSET MANAGEMENT STANDARDS

ASSET MANAGEMENT STANDARD	DESCRIPTION	ELEMENTS
AMS 01: Asset Management System, Strategy and Planning	Provides the Asset Management System framework and foundational documents.	• Asset Management Framework • Asset Management Policy • Strategic Asset Management Plan

ASSET MANAGEMENT STANDARD	DESCRIPTION	ELEMENTS
AMS 02: Asset Investment Planning & Decision Making	Documents how asset investment decisions (prioritisation and optimisation) are made to compile the final asset management plans.	• Asset Strategy Management • Network Development Planning • Asset Replacement and Refurbishment Planning • Asset Relocation Planning • Customer Planning • Project Planning • Development of the Asset Management Plan
AMS 03: Lifecycle Delivery	Documents how asset management plans are translated into more detailed work plans, namely project scopes, programme scopes or routine maintenance plans.	• Technical Standards and Legislation • Asset Creation and Acquisition • Asset Performance and Reliability Management • Maintenance Delivery • Capital Programme Delivery • Fault and Incident Response • Asset Decommissioning
AMS 04: Asset Insights	Documents how asset data standards and systems are defined and implemented in line with the Asset Insights Strategy in order to collect, store and utilise meaningful data to drive effective decisions around asset management activities.	• Data and Information Management • Asset Data Standards
AMS 05: Organisation and People	Documents the processes used to develop and maintain competent resources as well as how outsourced activities are aligned to asset management objectives.	• Competence and Behaviour • Supply Chain Management
AMS 06: Evaluation (of Cost, Risk and Performance), Review and Improvement	Documents how continuous evaluation of asset performance takes place to ensure alignment with asset management objectives.	• Asset Management Control, Review, Audit and Assurance • Asset Performance and Health Monitoring • Post Investment Reviews • Stakeholder Engagement • Sustainable Development

TABLE 5-3: VECTOR'S ASSET MANAGEMENT STANDARDS

5.4 Asset management key documents

Vector uses a range of document types to stipulate and control requirements. Each document type is represented in a hierarchy structure to ensure all information is aligned. This approach creates a "system of control" in relation to technical and business risks. The pyramid below represents Vector's document hierarchy.

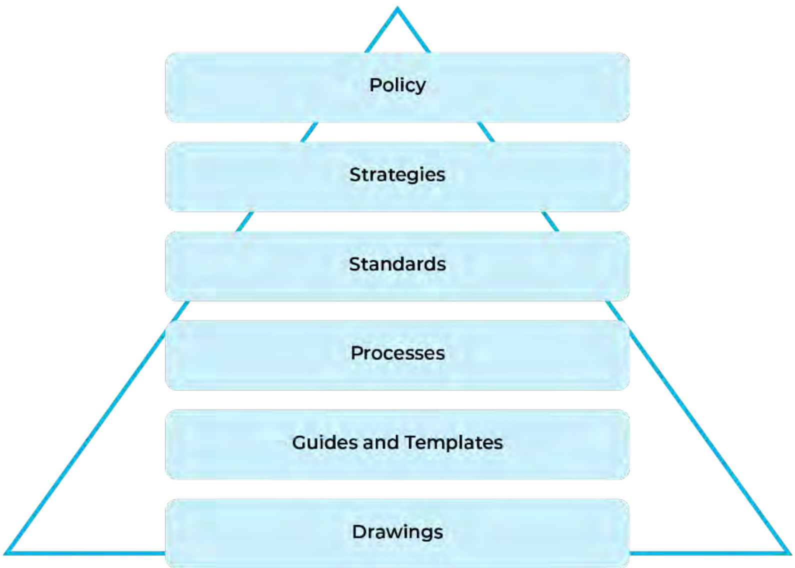

FIGURE 5.2: VECTOR DOCUMENT HIERARCHY

5.4.1 STRATEGIC DOCUMENTS

This table sets out the key strategic documents relating to Vector's asset management framework. Our strategic documents are subject to change control. The change control process obtains feedback and approval of the controlled document and related change impacts prior to publication.

DOCUMENT	ROLE IN ASSET MANAGEMENT PRACTICE
Asset management policy	This policy is Vector's formative asset management document. It defines the principles that guide all aspects of our asset management practice including the development of objectives and plans.
Strategic asset management plan	As part of our working towards alignment with ISO 55001, we are developing and defining the SAMP which documents our asset management objectives in line with our policy and operating context. The SAMP will link the organisational asset management objectives to the tactical asset management practice. The SAMP is still a work in progress
Delegated Authority (DA) framework	The DA framework applies to all business activities that have financial or non-financial consequences including contracts and expenses. The DA framework sets out specific approvals for particular transactions and governs the level of financial commitment that individuals can make on behalf of Vector. All decisions within our asset management practice that require expenditure or involve significant risk will be made under this policy and in accordance with Vector's project approval process.
Risk management policy	This policy provides the overarching risk management intent that Vector strives for. Its purpose is to: a) outline our key management objectives and the principles underpinning them, b) provide a framework for optimising opportunities and minimising risks, c) demonstrate Vector's understanding and commitment to promoting a culture of risk awareness throughout the organisation, and d) define key risk management roles, responsibilities, accountabilities and reporting requirements.
Health and safety policy	This policy sets out Vector's commitments and requirements for health and safety. Vector will conduct its business activities in such a way as to protect the health and safety of all workers, the public and visitors in its work environment.
Environmental policy	This policy sets out Vector's commitment to managing the environmental aspects of its businesses and sets out the standards expected of all workers.
Sustainability policy	This policy provides Vector's framework for managing environmental, social and governance risks and opportunities. It includes commitments to recognised international agreements and sets out the key principles by which sustainability will be adopted within the business.
Supply Chain and Procurement policy	This policy provides Vector's framework for building supplier capacity and capability enabling more effective management of network and supply chain risk, realisation of value and assist in achieving Vector's strategy to reduce its carbon footprint
Electricity safety and operating plan	This Safety and Operating Plan has been developed for Vector's electricity network to detail the controls in place to mitigate the risks that have been identified under the hazard and risk assessment processes for minimisation of harm to persons, property, the public and the environment, including emergency response.
Group data and information policy	The purpose of this policy is to govern and guide Vector's key data and information principles and includes everyone's responsibilities regarding data. Data and information refer collectively to all records and documents (both physical and electronic) used to describe and document Vector's business.
Asset header class strategies	These strategy documents facilitate the annual development of the AMP through formally recording asset strategies at the asset header class level for our different asset classes.

TABLE 5-4: VECTOR ASSET MANAGEMENT STRATEGIC DOCUMENTS

5.4.2 STANDARDS

Standards and specifications are an integral part of our asset management framework. These state the levels of service, performance targets, define intervention levels and minimum performance criteria. The table below lists the major standards that support the procurement, supply, commissioning, operation and maintenance of existing, new or replacement assets. Our technical specifications and engineering and maintenance standards are listed in detail in Appendix 2. These documents are improved under a defined change control process and document revision control process as described in Vector standard USD001 Controlled document management. Change control is the flow of documentation and change-related collateral between the document author, our field service providers and all end users in Vector. Change control obtains internal and if our field service providers are involved, external feedback and approval of the controlled document and related change impacts prior to publication.

ASSET STANDARD	ROLE IN ASSET MANAGEMENT PRACTICE
Planning standards (ENS series)	These standards guide the planning and development of Vector's overall distribution network architecture. They work in conjunction with the Security of Supply Standards (SoSS) service level metric to ensure that the network has sufficient capacity and capability to provide the required service levels, enable customer connections, accommodate growth and allow for the orderly and safe connection of distributed generation. These standards also set requirements that enable the appropriate operation of the network in accordance with the Network Operating Standards.
Maintenance standards (ENS and ESM series)	Vector has developed a set of maintenance standards for each major class of asset that detail the required inspections, failure modes, condition monitoring, maintenance and data capture requirements. Where a cyclic maintenance strategy is applied these standards also set out the maximum maintenance cycle frequency.
Network operating standards (EOS series)	These standards define protocols and procedures for operating and controlling Vector's electricity network, including contingency plans. They also inform the minimum requirements for network planning and design practices.
Design and construction standards (ESE and ESS series)	These standards and their accompanying standard design drawings cover the detailed design and installation of Vector's network equipment. They also include the data capture requirements for our asset management systems and plant in Vector's network.
Technical specifications (ENS series)	Technical specifications specify the materials and equipment to be used on the electricity network and the quality and performance requirements with which the materials and equipment must comply.
AS/NZ standards IEC standards	Australian and New Zealand standards as well as International Electrotechnical Commission (IEC) standards are referenced extensively in our standards and scopes of work.

TABLE 5-5: VECTOR STANDARDS

5.5 Asset management and asset management maturity

Developing our asset management maturity is a key focus of continuous improvement for Vector. We review our asset management practices using the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT).

At an overall level, our asset management maturity compares well with generally accepted New Zealand electricity asset management practices to ensure the ongoing safe and efficient operation of the electricity network. Our approach has matured progressively with our self-assessment improving year-on-year from an overall AMMAT score of 2.77 in 2019 to 2.87 in 2021. Our current score of 3.01 reflects the effort made to continuously improve our asset management practice.

Our objective as we go forward is to achieve a target score of three on each AMMAT rating criteria to align to ISO 55001 in the longer term. For our latest AMMAT self-assessment, refer to Schedule 13: Report on Asset Management Maturity in the Appendices section (Appendix 12). For full details on the AMMAT self-assessment framework and definitions of maturity levels please refer to the last tab of the Schedules 11a-13 AMP as set out by the Commerce Commission S13.AMMAT.

Set out below is an overview of the primary areas where ongoing improvements in our asset management practise are being implemented.

5.5.1 ASSET MANAGEMENT, ASSET MANAGEMENT STRATEGY AND ASSET MANAGEMENT POLICY

Our asset management policy broadly outlines the principles and requirements for undertaking asset management across the organisation (see 5.1 and 5.1.1 above for the broad outline of our policy). These strategies and goals then translate the strategic intentions into an asset investment strategy. These are documented in the Asset Management Plan. Technical standards, work practices and equipment specifications support the asset management policies, guiding the capital and operational works programmes.

5.5.2 COST, RISK AND SYSTEM PERFORMANCE

Asset management encompasses all practices associated with considering management strategies as part of the asset lifecycle. The objective is to look at the lowest long-term cost rather than short-term savings only. To achieve optimal asset management requires a balance between cost, level of risk and performance of the asset. We utilise a risk-based approach that considers the different failure modes of an asset, its condition, criticality scores, probability of failure, likelihood of consequences and a final risk score (our condition-based asset risk models are described in detail elsewhere).

A combined list of proposed projects and initiatives are then prioritised based on a set of agreed business objectives and values with the constraints of resources taken into consideration. The combined list contains our proposed projects and initiatives, high level cost estimates and estimated risks together with investment prioritisation.

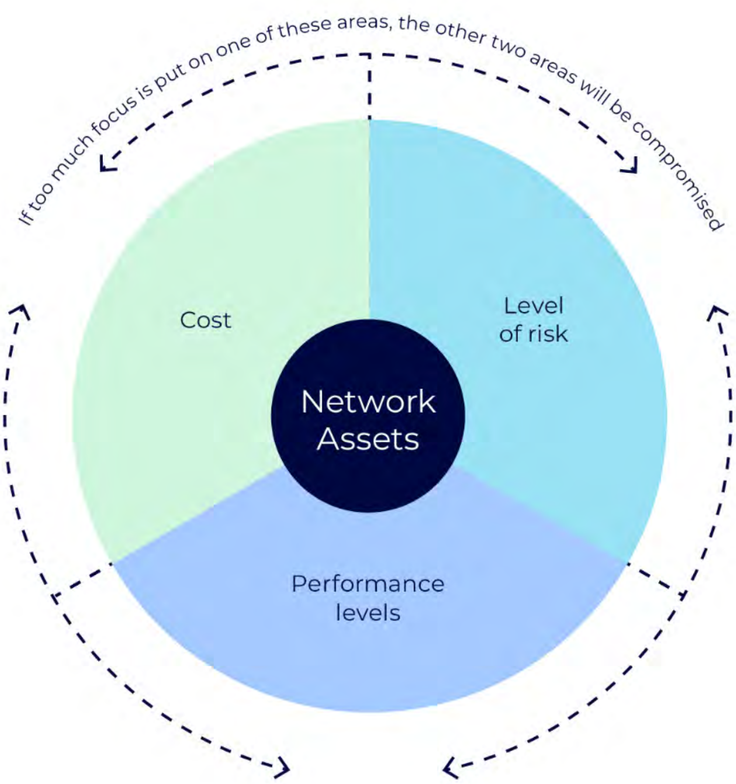

FIGURE 5.3: RELATIONSHIP, COST, RISK AND PERFORMANCE

COST

Improvements have been made to our process for creating business cases and justifications for capital projects to arrange capital budgets. A clear business process with stage gates has been compiled that describes the actions that need to be completed prior to moving past a stage-gate to the next stage in the budget and funding process. Our business cases state the risk and need that drives the requirement for a project, alternative options that were considered and the cost for each option. Our works cost estimates are detailed providing an overview of the total estimated cost of the works, the portion that is required to develop the design of the works, funding required for early procurement of long lead items and the portion required to move to full project funding. Business cases and cost estimates undergo a rigorous peer review process and then a controlled approval process via our SAP business software workflow procedure.

For Vector's internal use, our Project-on-line application enables a live and continuous update of the progress of projects, both physical delivery and financial progress. We have rolled out Project-on-line as the tool to manage and control the delivery of capital projects. This tool allows integrating project time-line forecasts with financial forecast for the delivery of capital projects. It provides a one-stop-shop for improved visibility of projects, associated risks and challenges to the delivery of projects.

A Governance Group is in place with representatives from the Network Performance team and Capital Delivery team that meet on a weekly basis to discuss the asset management plan, challenges, risks, issues, cost, and scope changes. Scope changes are formally recorded.

LEVEL OF RISK

Our risks are registered in our Active Risk Manager (ARM) together with controls, actions, assignment of responsibilities and target dates for assessment, review and completion. We use a risk matrix that considers consequences and likelihood to assess and score risks. The risk scores are assigned in our ARM software application. Initiatives to address a risk could also present itself as an opportunity for new solutions and innovations. In certain instances, risks are accepted within the business and such decisions are recorded in ARM as well as in the corporate risk register.

PERFORMANCE LEVELS

Our performance levels for our network supplies are stated in our Security of Supply standard. Our SAIDI and SAIFI are calculated in our HVSPEC application, and the data is retained for reporting and analysis and reported annually to the Commerce Commission in our compliance statement. Our average network customer base is calculated using our Gentrack billing and revenue system application.

5.5.3 ASSET HEALTH, MODELLING AND INVESTMENT SCHEDULE

For our asset fleet we have developed an asset strategy for each Header Class asset. These strategy documents clearly describe the asset class equipment, their status and condition, challenges, future management, and maintenance and replacement strategies. These strategy documents thus informs and facilitate the annual creation of the capital investment programs and capital budget. They are updated annually to coincide with the development of the annual asset management plan.

Condition Based Asset Risk Management (CBARM) models have been developed for all distribution assets. These models that uses condition data, risk data, as well as environmental conditions and location, provide a data driven basis for the planning of projects and programmes rather than a pure focus on annual planning within a defined financial budget. Asset data supports and underpins these CBARM models, which in turn inform our asset health knowledge and support the development of our asset header class strategies, renewal and replacement programme and, capital budgeting. The figure below is a flow diagram for our CBARM models.

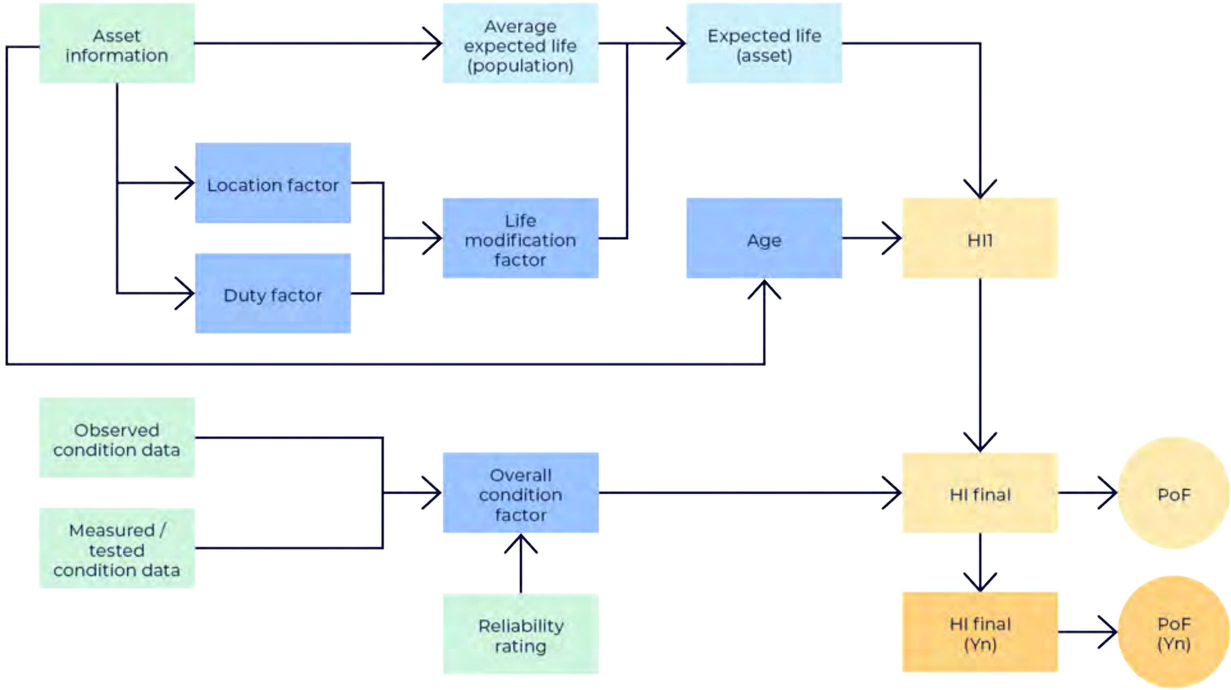

FIGURE 5.4: CBARM MODEL FLOW CHART

5.5.4 SYSTEMS AND INFORMATION MANAGEMENT DATA

Investments have been made to our core systems through the SAP Planned Maintenance (SAP-PM) project which has allowed for a consistent approach to the management and delivery of planned maintenance across our field service providers. The project has delivered a suite of maintenance standards that provide for improved asset data quality and volume.

To move away from a largely supply-driven mindset of the electricity industry, Vector has adopted bottom-up modelling to understand energy-related trends on the customer side and sets the foundation for 'customer centricity' in our electricity distribution network and asset planning, Vector's granular customer model includes all 600,112 customers connected to Auckland electricity network. It can zoom in on specific customer attributes, specific network locations and extreme events, without being exposed to the limitations of small samples. It uses data from Stats NZ (census data) and detailed property information for all rateable buildings in Auckland. Half-hourly metering data is also used as well as a host of other data sources. The granular customer model is the foundation of our scenario model, which assesses the impact of peak demand and energy consumption as a result of new technology adoption. Section 10 describes how the scenario model is used for load forecasting as part of the network planning process.

5.5.5 ASSET MANAGEMENT DOCUMENTATION, CONTROLS AND REVIEW

Document control is stipulated and governed by our standard USD001, Controlled Document Management standard. Policies, strategies, and standards are circulated for reviews and updates via our Sharepoint application including our external partners such as field service providers or consulting engineers. This software platform allows automation in terms of review dates, completion of review dates, review comments etc. It enables a high level of control of the documentation process and a historic record of reviews. Updates of asset management documents, standards, standard drawings are issued via an automated process in this application. Each asset management document has a revision number, current date, and a date at which it needs to be reviewed.

This document control process also applies to outsourced works. The issuing, changes and return of changed documents are controlled via our Meridian software application with a revision recording and history of changes system in place as part of the application.

5.5.6 COMMUNICATION OF THE ASSET MANAGEMENT PLAN

Our website portal (www.vector.co.nz), provides a wide range of asset management information to external parties. It provides information with regard to new connections, connection of distributed generation, outages and faults, work in close proximity to our networks, planned outage notifications, and our asset management plan amongst others. Our asset management plan, for both OPEX and CAPEX are formally communicated with our field service providers via formal meetings and programme of works schedules.

Vector has also launched an Open Data Portal with network asset location information, including distribution and sub-transmission overhead lines and underground cables on Vector's electricity distribution network. The site allows third parties the ability to access location information for electricity and gas feeders electronically. In addition to creating map views, third parties can download the data or connect their systems directly to Vector data. This initiative ensures that infrastructure companies, construction companies and entities like Auckland Council and Civil Defence have access to up-to-date information about Vector assets. This is also another way in which Vector can assist construction companies to prevent third party asset damage.

Our Capital Delivery Team has three team members that act as the main interface between our project management team and contractors and field service providers, to communicate the asset management plan. We also have a quarterly contractor forum meeting that involves external parties over and above field service providers, e.g. design consultants and all other contractors including our panel of civil contractors.

We also have quarterly "All Hands" sessions for the wider Vector team at which the asset management plan is presented and specific topics drilled into.

5.5.7 AUDIT OF THE ASSET MANAGEMENT PLAN

Entrust, Vector's majority shareholder, biennially conducts an independent review of the state of Vector's network that includes an assessment of our asset management plan, targets, and outcomes. With support from external asset management specialists, we use these reviews to address gaps and inform our plans to improve our asset management practice. Vector also undergoes annual safety audits of its network and management practices in terms of NZS7901, Public Safety.

5.5.8 OPERATIONAL MANAGEMENT IMPROVEMENTS

Our current SCADA system will be replaced with an advanced distribution management system (ADMS). This system will be fully commissioned within the coming months. The ADMS will assist control room personnel with monitoring and control of the distribution system in an optimal manner while improving safety and asset protection. In addition to the traditional SCADA single line diagrams the ADMS also provides a geographical view of the network by being fully linked to our geographical information systems (GIS). ADMS includes the "traditional" SCADA functions of data acquisition and control but has the functionality for near real-time analysis and optimisation of the distribution system. The ADMS will enable us to further build on and implement a state-of-the-art Outage Management System and other advanced applications such as FLISR (Fault Location Isolation and Service Restoration) which will further enhance our SAIDI count and reduce outage times.

SECTION 06

Governance, risk and data

6 – Governance, risk management and information management

6.1 Overview

This section provides an overview of Vector's governance and organisational structure, accountable for delivering effective and fit for purpose asset management planning. Fundamental to effective governance is a strong awareness and focus on risk management. Therefore, this section also includes an overview of our enterprise risk management framework, key risk practices and event management documentation that includes emphasis on high impact, low probability risks. Finally, our data and privacy management practices are covered, which includes a summary of information systems and our approach to cybersecurity. These elements are key enablers in ensuring Vector's asset management practice.

6.2 Governance and organisational structure

Vector's asset management governance and organisational structure is shown in Figure 6-1. This structure provides oversight and leads all aspects of our asset management practice.

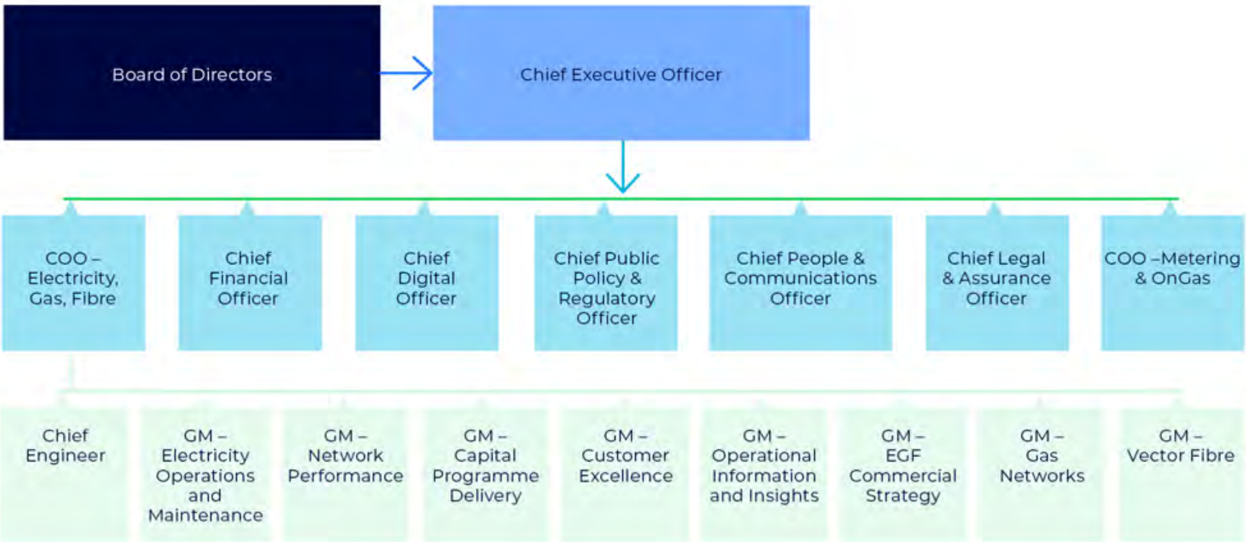

FIGURE 6.1: VECTOR'S ASSET MANAGEMENT GOVERNANCE AND ORGANISATIONAL STRUCTURE

Figure 6-1 pictorially represents the governance and organisational structure accountable for delivering effective and fit for purpose asset management planning for Vector's electricity distribution business. An overview of the asset management accountabilities and responsibilities within three levels of this structure are set out below.

- **Board of Directors** – At the highest level, the Board of Directors provides governance over all aspects of Vector's asset management practices on behalf of Vector's shareholders. The board exercises oversight of the objectives of asset management (refer Asset Management Systems), its strategic direction, process for investment approvals and the customer service level outcomes achieved by Vector's electricity distribution network. Overall budgets, significant expenditures and asset investments are reviewed and approved at the board level.
- Vector's Board of Directors maintains its asset management oversight through the implementation of governing policy, a delegated authority framework, management reporting and periodic reviews including internal and external operational audits. The board also receives performance reporting against key service levels and regulatory reliability targets.
- Full details of Vector's board members, the executive leadership team and our corporate governance structure are available on our website.
- **Chief Executive Officer** – Under the delegated authorities' framework, the approved strategic plan, approved annual budgets, and day-to-day operation of the business is the responsibility of the Chief Executive Officer (CEO). The CEO maintains oversight of Vector's asset management practices, including effective risk management (both strategic and operational), service level outcomes, strategic direction and investment approvals. To assist with this oversight, the CEO receives performance reporting against key metrics and service levels which include reporting against regulatory reliability targets.
- **Chief Legal and Assurance Officer** – Under delegation from the board and the CEO, the Chief Legal and Assurance Officer is accountable for providing Vector's legal counsel as well as policy, frameworks and governance for enterprise risk and resilience, internal audit, health, safety and environment, compliance and privacy (via a dedicated Privacy Officer). Responsibility for the delivery of these functions at a business unit level is appropriately disseminated and delegated throughout the business through dedicated management functions and ownership models.

- **Chief Operating Officer – Electricity Gas & Fibre** – Under delegation from the board and the CEO, the Chief Operating Officer (COO) has full responsibility for Vector's electricity asset management practice. This includes the establishment and enforcement of Vector's Asset Management Policy, the overall performance of Vector's electricity distribution network, development and implementation of the approved AMP, and budgetary control within the delegated authorities' framework.
- **Chief Engineer** – Integral in strategic business model design and strategic business opportunities, this role works alongside project teams and executive sponsors to ensure Vector's electricity and gas networks and services are of the best practicable quality, delivered safely and effectively.
- **General Manager Electricity Operations and Maintenance** – Vector's field staff are managed through an outsourced contracting model. As such, the GM Electricity Operations and Maintenance is accountable for the contractual relationships and performance of field crews delivering our maintenance programme. Work is centred around the delivery of maintenance plans in accordance with Vector standards and reactive response to outages.
- **General Manager Network Performance** – This role is accountable for future network planning, capital and maintenance investment planning, and developing detailed asset management plans and standards for all asset classes required to achieve Vector's asset management objectives.
- **General Manager Capital Programme Delivery** – This role is accountable for the delivery of the annual capital programme, including project engineering, project management, and procurement and tendering of capital works.
- **General Manager Customer Excellence** – This role is accountable for providing the key link between asset management delivery and Vector's customers. The role leads our relationship with retailers and customers to ensure the relationship is continually strengthened and supported.
- **General Manager Information and Insights** – This role is accountable for managing Vector's electricity information and data assets. The role ensures information compliance with regulatory and privacy requirements and provides supporting business intelligence to inform operational decision making.
- **General Manager Commercial Strategy** – This role supports Vector's commitment to its asset management objectives and vision by driving key reliability and strategic initiatives.
- **General Manager Gas Networks** – This role is accountable for asset management planning and delivery for Vector's gas distribution business. All asset management roles support the enhancement of electricity asset management through synergies and cross-functional skillsets.
- **General Manager Fibre** – This role is accountable for asset management planning and delivery for Vector's Fibre business.

The governance framework overarching each of these roles is supported by the Code of Conduct and Ethics – the Vector Way, Vector's Delegated Authority Framework (DAF), and position descriptions for each role. Vector's Board has delegated specific authorities to the CEO and authorised delegation of certain authorities to other levels of Vector's management. The limits and rules applied to delegations are prescribed in the DAF documentation and govern the authority to commit to transactions or expose Vector to a risk.

Vector's Enterprise Resource Planning (ERP) System (SAP) is the primary management system used to implement the DAF. Financial delegations for approvals under the DAF for OPEX and CAPEX are set and managed within Vector's SAP system. A periodic audit of the DAF is undertaken to ensure ongoing compliance. The ERP system also provides control of asset management workflows, as well as the management of information that enables our asset management and project management practices.

6.3 Risk management

6.3.1 ENTERPRISE RISK POLICY AND FRAMEWORK

Risk management practices form an integral part of Vector's asset management processes. Vector's Risk Management Policy establishes clear principles which provide for a purpose-built flexible approach to the application of risk management across Vector.

Our activities in risk:

a) Create and protect value in our organisation;

b) Form an integral part of all organisational processes and decision-making;

c) Explicitly address uncertainty;

d) Are systematic, structured and timely;

e) Are customised to suit our organisational context and individual business activities;

f) Take into account human and cultural factors;

g) Are transparent and inclusive; and

h) Are dynamic and responsive to change.

The above principles form the basis of Vector's risk management approach allowing for the development of risk management objectives and a clear framework that is applicable across the Vector Group. Our Enterprise Risk Management (ERM) framework is based on the international standard for risk management, ISO 31000. It allows for a single, company-wide view of risk, aligning several profiles and contexts across Vector, to support the achievement of our strategic objectives.

Vector's ERM framework (summarised below in Figure 6-2) is focused on understanding, monitoring and proactively treating risks within the business. The management and tracking of identified risks and associated treatment plans is undertaken using Vector's ERM system - Active Risk Manager (ARM).

FIGURE 6.2: VECTOR'S ENTERPRISE RISK MANAGEMENT FRAMEWORK

Vector's risk management processes and tools are embedded within its business operations to drive consistent, effective, and accountable decision-making. Consistent with the "Three Lines Model", all Vector people are responsible for applying Vector's ERM framework within their individual roles to proactively identify, analyse, evaluate, and treat risks. This risk mindset has been implemented through:

- Awareness of risk management's value at operational, executive team and Board level;
- Embedding of risk assessments and discussions within key decision-making processes; and
- Continuous development through both internal and external reviews.

6.3.2 RISK PROFILES

Vector operates both a top-down and bottom-up approach to risk management.

At the top level, the board sets the risk appetite and strategic direction for the business. The board has established a Board Risk and Assurance Committee (BRAC) [1] which assists the board in providing oversight of Vector's risk and assurance policies and practices, monitors risk performance concerning Vector's risk appetite and business objectives, provides guidance regarding the development of the ERM framework, and ensures rigorous processes for internal control and legal compliance.

Spanning across Vector's portfolio of businesses, Vector's Group Risk function is tasked with the ongoing development and implementation of the ERM framework and risk processes. In addition to monitoring the changing business landscape and macro-economic trends, this function integrates and works with all Vector business units to facilitate smart risk-based decision-making as well as consistent bottom-up risk analysis and evaluation of risk against Vector's risk appetite. These perspectives inform the development of the Group Key Risk Profile which provides both the board and executive team with a consolidated view of:

(i) the strategically focused risks which could have a significant impact on the long-term value and sustainability of Vector's business; and

(ii) the material operational risks facing Vector as part of its business-as-usual activities which require significant oversight and control.

To inform the Vector Group key risk profile, business unit and operational risk profiles are developed based on the objectives and operating context specific to each business unit. Figure 6-3 shows the alignment of Vector's risk profiling structure.

[1] The BRAC contains at least three members of the board.

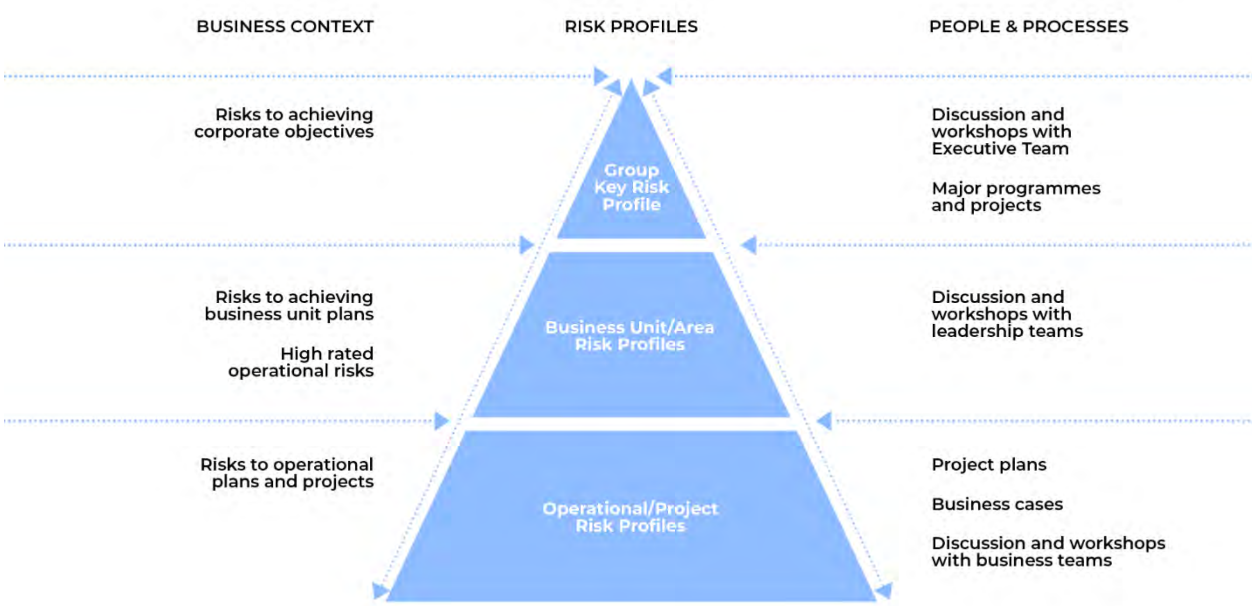

FIGURE 6.3: VECTOR'S RISK PROFILING STRUCTURE

6.3.3 ELECTRICITY DISTRIBUTION RISK MANAGEMENT

The development of Vector's electricity distribution risk profile incorporates the use of risk groupings. Eight risk groupings have been established within Vector's ERM system (Figure 6-4) to consolidate risk across the business unit. This approach avoids the use of siloed team risk registers which often either repeat risks across many registers or neglect them completely. The risk grouping approach also aids in the identification of risk and supports risk activities undertaken throughout the business, such as critical site reviews or High Impact, Low Probability assessments.

FIGURE 6.4: ELECTRICITY DISTRIBUTION RISK GROUPINGS

Risks are analysed and evaluated against Vector's risk criteria and then treated to modify the risk level if required. Risk treatment considers the level of risk tolerability which is informed by applicable legislation and industry standards (including the Health and Safety at Work Act and the Electricity Act).

Vector's risk management processes are integrated into the asset investment process and the development of asset class strategies to ensure appropriate treatment plans (which supplement existing controls) are developed and prioritised. Maintenance standards are linked to asset risks through Failure Mode and Effects Analysis and corrective maintenance activities are prioritised using a Risk Based Approach (RBA). Asset investment considers asset condition and risk through the development of our Condition Based Asset Risk Management (CBARM) model to ensure the health of Vector's asset portfolio remains acceptable.

In line with the Institute of Internal Auditors' Three Lines Model, Vector also operates an internal audit function that establishes an assurance programme to monitor risk management functions and applicable business processes. This independent and objective function conducts and coordinates audits and performance reviews to provide assurance and confidence in the effectiveness of the risk management framework and supporting activities.

6.3.4 HIGH IMPACT LOW PROBABILITY (HILP) RISKS

Included in Vector's electricity distribution risk management process is the identification and treatment of High Impact, Low Probability (HILP) risks. A dedicated risk grouping has been assigned to ensure HILP risks are easily identified and managed. Our risk processes require HILP risks to be treated the same way as other "high" risks and managed accordingly. This ensures that, regardless of likelihood, high-consequence events are appropriately considered.

Network resilience and the ongoing management of HILP risks is a priority for Vector with proactive investment allocated to manage future events. We undertake regular critical site reviews, monitor reference material and global trends, have developed comprehensive event and contingency management plans and have engaged a variety of experts to help influence our planning and management of HILP events.

Identification and management of HILP risks include consideration of both our internal and external operating environment. Figure 6-5 below provides a representation of HILP events influenced by a range of factors that require ongoing and evolving management to both prevent the occurrence and mitigate the impact so far as is reasonably practicable.

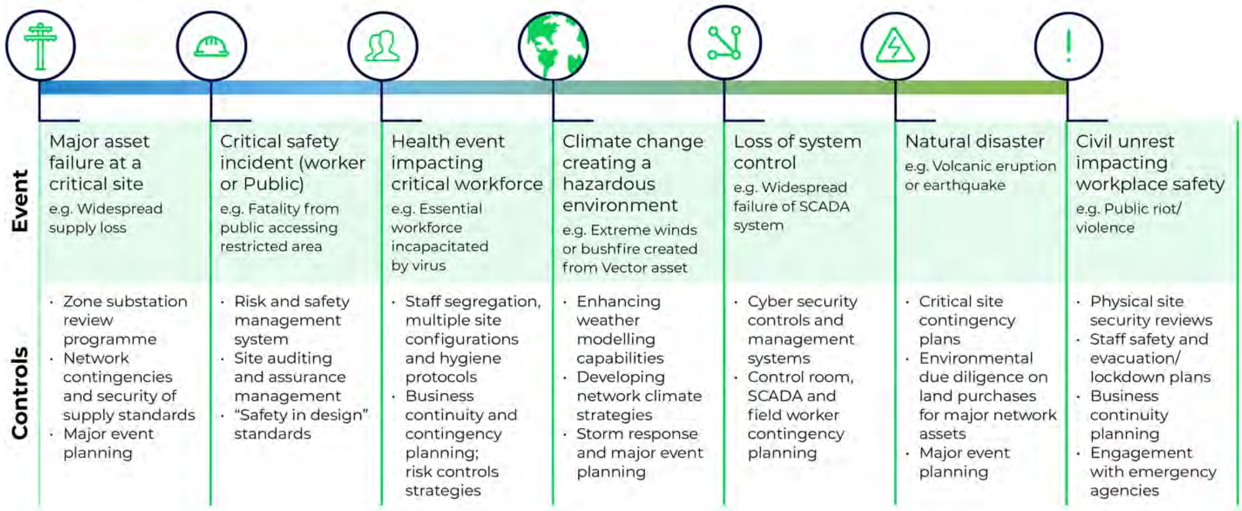

FIGURE 6.5: EXAMPLE OF HILP EVENTS

6.4 Event management and emergency response

As a supplier of an essential service to more than 600,000 ICPs across Auckland and a nominated "lifeline utility" under the Civil Defence and Emergency Management (CDEM) Act 2002, Vector has developed a suite of documentation that defines our key event management plans and processes (detailed in Table 6-1). This documentation ensures Vector maintains coordinated and clear management protocols to respond to events efficiently and effectively.

DOCUMENT	DESCRIPTION
Business Continuity Management Policy	Formal representation of Vector's commitment to business continuity management, which forms an essential part of Vector's enterprise risk management framework. Defines key business continuity management roles, responsibilities, accountabilities and reporting requirements. Approved by the Board, it is consistent with the following Standards: • AS/NZ 5050:2020 "Managing disruption-related risk" • ISO 31000:2018 "Risk management – Guidelines" • ISO 22301:2019 "Security and resilience - Business Continuity Management System – Requirements" • ISO 22313:2020 "Societal security – Business continuity management systems – Guidance"
Crisis Management Plan	Provides the enterprise-wide framework and structure to assess and respond to any crisis-level incident or event affecting Vector, its customers and/or employees, contractors, and other stakeholders. Takes account of both the operational response and broader considerations including staff, customer and wider stakeholder engagement and support. Includes the Incident Management Guideline, which provides direction on how to categorise incidents - this categorisation determines the appropriate response team, response plan and escalation hierarchy. Crisis management exercises and regular plan reviews are undertaken to ensure usability and understanding and support continuous improvement of the plan.
Crisis Communications Plan	Standalone plan governing the communications and external relations approach and processes during a crisis, emergency or business continuity events.
Networks Event Management and Investigation Process	A formal focused and coordinated process to effectively manage network events. The process defines the approach such that Vector can:

DOCUMENT	DESCRIPTION
	• Recognise, assess and respond to an event quickly and effectively • Notify the appropriate individuals and organisations about the event • Organise response activities • Escalate response efforts based on the severity of the event • Recover from event • Gather evidence to support and complete investigations
Specific Event Response Processes	Individual and detailed processes that ensure Vector is prepared for (and responds efficiently to) specific events that may occur on the network. These events include credible incidents and emergencies, for example storm response.
Business Continuity Plans	Individual business unit / team plans identify the critical functions and services provided by a unit/team and outline the recovery procedures to be undertaken during a disruptive event to maintain or resume these functions.
EOC Emergency Evacuation Plan	Ensures Vector's Electricity Operations Centre (EOC) is prepared for, and responds quickly to, any incident that requires the short, medium or long-term evacuation of the EOC. Vector's network control centre has a fully operational disaster recovery site. Regular evacuation exercises are held to ensure evacuation of the control centre can proceed smoothly.
Switching Plans	Restoration switching plans developed for each zone substation at a feeder level.
Emergency Load Shedding Obligations	Vector is required under the Electricity Industry Participation Code (2010) to provide emergency load-shedding by way of Automatic Under-frequency Load Shedding, to maintain the electricity security of the grid and avoid cascade trippings under emergency conditions.

TABLE 6-1: VECTOR'S EVENT MANAGEMENT PLANS AND PROCESSES

6.5 Privacy

Vector takes its obligations under the Privacy Act very seriously. The volume and potential sources of data which are required to effectively manage and operate the network continue to expand. For example, new network and customer devices generate increasingly important information about consumption patterns, faults, performance and resilience which enables us to manage the network more efficiently and effectively. Vector understands its legal obligations and also its "social licence" to use this information responsibly and therefore has taken a conservative view on all data which relates to our customers, their physical location or their property. Vector has established protocols which define how any personal data is required to be protected, managed, and used by approved personnel.

Our data governance programme takes a holistic view of how data is managed and governed and specifically considers privacy across all areas of our data. A number of roles exist which assist in Vector's adherence to privacy obligations.

FUNCTION	ACCOUNTABILITY
Privacy Officer	Setting policy and supporting privacy-related activities or issues. Dealing with privacy breaches, including any reporting requirements.
Enterprise Information Management	Development and implementation of the Group Data and Information policy. This function supports all aspects of information management and provides operational support to the privacy officer.
Cyber Security	Establishment of systems and processes for the protection of all data.
Operational Information Management	Operational management, quality assurance and improvement of data.
Data Owners	Accountable for ensuring appropriate processes and systems are in place for all sensitive data and for implementing the requirements of data-related policies and procedures.
Data Steward	Responsible for implementing the requirements of data related policies and procedures.

TABLE 6-2: DATA GOVERNANCE ACCOUNTABILITIES

6.6 Asset management information systems

Vector has a suite of information systems that support its asset management practice.

6.6.1 PRIMARY SYSTEMS

Many of Vector's information systems operate through an integration layer that extends across these systems and enables the reporting and data analytics that support Vector's asset management processes. The following table provides an overview of the primary systems and provides insight into how they support asset management.

PRIMARY SYSTEM	FUNCTIONAL OVERVIEW
SAP	SAP is Vector's ERP System. It contains records for all assets and is used for managing the asset lifecycle from procurement and operation to maintenance and disposal. SAP also provides financial management related to asset management and project management
SAP Planned Maintenance (PM)	SAP PM is our asset maintenance management system used for planning, scheduling, executing and recording all maintenance activities on our assets.
GE Smallworld	This system provides the geographic, schematic and connectivity information used in managing Vector's network assets
ARC-GIS	This system provides geospatial visualisation and analytics tools
Siebel	Siebel is Vector's Customer Relationship Management system. This system is used for managing customer requests for new connections, quality of supply complaints management, and fault and outage management
Gentrack	Gentrack provides records for all connected ICP's as well as their regulatory and market attributes. It is used to manage energy consumption, revenue assurance and interfaces with the Electricity Authority registry
Data Analytics Layer	This is a bespoke integration layer that provides reporting, monitoring and associated analytics related to network assets. It is a critical source of information for most of Vector's asset management processes
Siemens Power TG	This is Vector's SCADA system and is used to monitor and control operations on the network as well as provide data on network loading and other critical asset data
GE Power On	This is Vector's ADMS (Advanced Distribution Management System). This system is still in implementation phase 1 and will be replacing Siemens Power TG in RY 2024. It will be used to monitor and control operations on the network, and record and provide critical asset data.
ARM	ARM is Vector's corporate risk management system. Under the Corporate Risk Policy, all asset management risks are recorded, prioritised and managed through this system Also, ARM is used as an enterprise incident management system, which includes recording of incidents and investigations.
Stationware	Stationware is Vector's system to record and manages all protection settings in its primary and distribution networks

TABLE 6-3: PRIMARY SYSTEMS OVERVIEW AND INSIGHTS

6.6.2 OTHER IMPORTANT SYSTEMS

Vector uses several other information systems, computer models and computer-based tools in the management of its electricity distribution assets. In particular:

- **DERMS:** a Distributed Energy Resource Management System, this application is constantly processing and optimising the use of any DERs connected to it. This optimises asset utilisation through, for example, peak management via community battery storage and ripple control. The system has a 24-hour load forecast across the overall network down to a distribution feeder and will automatically dispatch DERs to overcome network constraints or can provide a forecast of network headroom to customers so that they can optimise their DER(s) accordingly. This minimises customer impact, network reinforcement and costs. As more DERs are connected the importance of and reliance on this system will increase.
- **OSIsoft PI:** is a real-time network performance management system that utilises data from various corporate systems (e.g. SCADA – see above) and provides a Microsoft EXCEL link to support analysis. This tool provides a permanent archive of historical network data
- **Granular Customer Model and Database:** this is a bespoke model implemented as SQL Database that brings together all of Vector customer and energy information with information from third party sources (e.g. socioeconomics)
- **Scenario Model and Network Allocation Model:** this is a bespoke bottom-up customer load model implemented in Microsoft EXCEL to analyse the impact of future changes on network demand. It is used in Vector's network planning practice to forecast the yearly maximum demand for summer and winter periods at a feeder and zone substation level. It makes use of information from recorded historical demand data, the forecast scenario model and known step loads from large projects
- **Forecast model:** this is a bespoke model implemented in Microsoft EXCEL. This model established current loading by normalising for natural variability. It then provides load forecasts across network levels by combining scenario model results allocated by network asset, new or upgraded large-scale customer load requests and manual re-adjustments due to changes in topology
- **Network constraint model:** this is a bespoke model implemented in Microsoft EXCEL. It is used in Vector's network planning practice to forecast the ability to backstop individual feeders or entire zone substations in the event of failure. The model uses the demand forecast, individual feeder/zone substation capacity and backstop points between feeders to highlight any shortfalls in backstop capacity for the period of the AMP

- **Digsilent:** is a network modelling tool that provides network power flow and fault levels analysis. It uses information from Smallworld, the Demand Forecast, the Rating Datasheets and Gentrack to maintain its network model. This includes scripts that enable the automatic execution of certain workflows
- **CYMCAP:** is a software tool that calculates cable ratings based on ground thermal conductivity test results and standardised cable installation practices. It is used to set the ratings of all subtransmission cables
- **HV Spec:** is Vector's system of record for all outage information, including fault interruption and duration data. This system is used to calculate and report on Vector's reliability measures such as SAIDI and SAIFI
- **Rating Datasheets:** this is a Microsoft EXCEL based database that contains summer and winter ratings for subtransmission plant and considers future network constraints. Our rating datasheet is manually updated on an annual basis.
- **Ion:** Centralised server for data gathering all power quality metering information from zone substations and GXPs
- **Zone Substation Equipment Ratings:** this is a Microsoft EXCEL based database that contains details of the ratings of the primary plant in our zone substations and at GXPs. It considers N-1 ratings for winter and summer conditions and identifies points of constraint. It is manually updated on an annual basis

6.7 Information and data management

Vector has taken a coordinated approach to the management and governance of its information and data assets. The following five capabilities have been established reflecting the operational, strategic and governance overlaps across the disaggregated functions.

Enterprise Information Management: This function delivers and supports the information management program that manages the people, processes and technology that provide control over the structure, processing, delivery and usage of information required for management and business intelligence purposes. Providing compliance and governance frameworks applicable to both physical and electronic information.

Network Information Management: This function provides governance to the operational application of information and data management across the electricity network's systems of record for assets and operational activities, through the development, execution and supervision of plans, policies, programs and practices that control, protect and enhance the value of data and information assets throughout their life cycles.

Data Platforms: A technical function, this team is responsible for the management and development of the data and analytics application platforms.

Business Intelligence: Primarily a technical function, this team provides the data integration, visualisation and reporting capability to the business.

Analytics & Insights: Provides the technical analytics capability and highly specialised business operational knowledge to support all core functions within the Networks business and to provide the research, advanced modelling and data science capability.

6.7.1 DATA GOVERNANCE

Vector's Group Data and Information Policy and Information Governance Framework are the foundations that set out the governance requirements and operating model for the information lifecycle. This covers both information in electronic and physical form, as well as disciplines for the process of creating, obtaining, transforming, sharing, protecting, documenting and preserving data. In preparing the policy and operating model, Vector has followed the principles and framework as set out in the Data Management Association's body of knowledge [1].

The Group Data and Information Policy is supplemented and supported where necessary by other operational and policy documents including our Privacy Principles and Cyber Security Policy.

[1] DAMA-DMBOK, Data Management Body of Knowledge, Second Edition, DAMA International

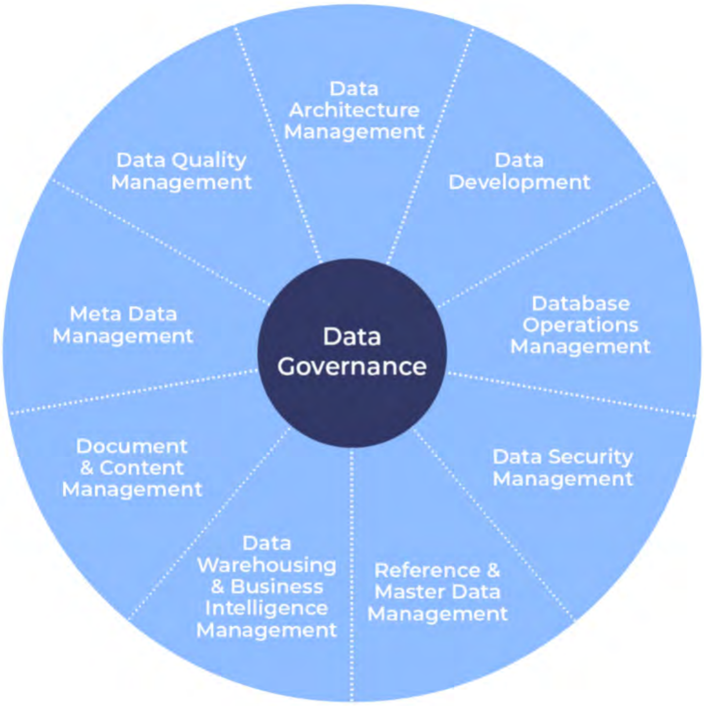

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FIGURE 6.6: DATA MANAGEMENT ASSOCIATION FRAMEWORK

6.7.2 OPERATING MODEL

Vector's data and information management model is represented in the diagram below. Operationally, the Enterprise Information Management (EIM) function within the Digital Centre of Excellence provides capability horizontally across the different business units. Within each business unit, data stewards have been established to work with the defined data owners to ensure that business (i.e. operational) and governance requirements are met for each data set. The data stewards are trained and overseen by Enterprise Information Management.

Vector operates a virtual Information Governance Council responsible for setting and supporting the implementation of the Group Data and Information policy. This includes being the escalation point for data related events and advice on the treatment and usage of data. Importantly the Council is made up of core disciplines and functions from across the business that impact privacy and data management including, but not limited to, Enterprise Information Management, Privacy, Legal, Information Management and Data and Analytics. In addition, Cyber Security and Digital Architecture teams also provide subject matter expertise where required to support the Council in managing risk and maintaining good practice. In line with good governance and given the importance of strong data and information management in the success of our Symphony Strategy, the Council reports directly to Vector's Executive Team.

Operationally, the electricity business maintains a dedicated Networks Information Management team to perform the majority of the data activities as depicted in the box titled "Operations – Information Management". This team is responsible for defining and ensuring the implementation of data standards, as well as managing the data within the System of Record for asset, asset performance, geo-spatial and customer data. Also, the team also manages regulatory reporting (including one off requests) as well as managing other third-party data requests such as location information and asset information.

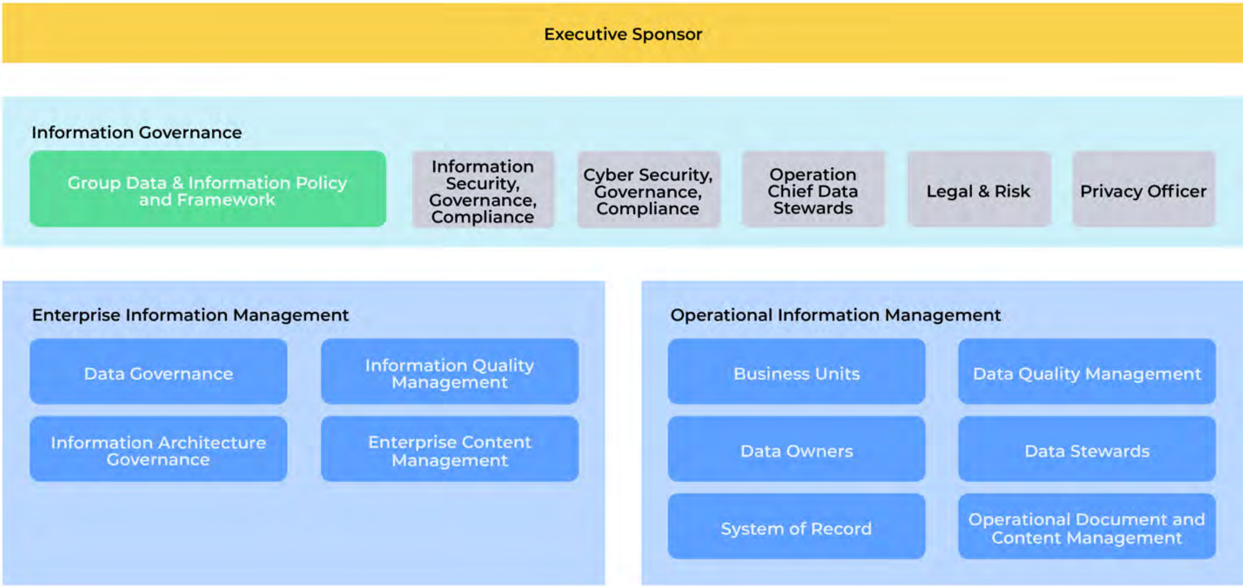


FIGURE 6-7: VECTOR'S DATA AND INFORMATION MANAGEMENT MODEL

6.7.3 DATA QUALITY AND OPPORTUNITIES FOR IMPROVEMENT

The Network Information Management function has an ongoing programme of work relating to the assurance and improvement of data that support the asset management practice. The programme has had a key focus on the alignment of asset management data with operational data, and a number of significant improvements have been completed since the last AMP.

1. Improvement of SCADA, GIS and SAP data alignment- Completed.
2. Improvement of GIS network connectivity – Completed.
3. Improvement of Zone Substation internal schematic consistency – Completed.
4. Resolution of legacy unknown cable types – Completed.
5. Improved access to smart meter data from retailers – kWh smart meter data - Completed.
6. Capture of network designs in GIS – Completed.

An ongoing focus remains on improving LV data, with the following key initiatives underway.

1. Improvement of Customer contact and address data.
2. Improved access to smart meter data from MEPs (Network Operational Data).
3. Improvement of network visibility including LV connectivity, ICP service fuse connection and phase assignments.
4. Enhancement of asset master data.
5. Improved access to Real-Time operational data.
6. Enhancement of OT Timeseries data management.

6.8 Cyber Security

In the context of our Asset Management Plan, our strategy regarding cyber security continues to be focused on addressing two key categories of risk:

1. The protection of critical network assets from unauthorised access that could result in disruptions to service or physical damage
2. Safeguarding and restricting access to any personal/customer data that is used for network management purposes

At the core of this focus is the protection of Vector people, processes, data and systems from cyber security risks. Our operating environment is one where the number, sophistication and impact of malicious cyber security threats continues to grow, and we have observed increased numbers of large-scale, well publicised breaches. Threat actors have also started using more legitimate tools in their operations, including native operating system files, IT software and penetration testing tools; all helping them in their efforts to stay under the radar; Increased attacks though the software supply chain as well as threats against cloud, IOT and mobile platforms as well as the use of sophisticated ransomware are more common. Threat actors are changing their initial access vectors as the digital attack surface and vulnerabilities shift.

As Vector continues its digital transformation journey, it also navigates these risks. Continuing to maintain an effective and mature security posture is a key priority and an area in which we continue to invest sufficiently to ensure we appropriately manage these cyber security risks.

We have continued to improve our ability to detect and prevent potential cyber security threats via our Security Operations Centre (SOC), which provides 24/7/365 monitoring of our Information Technology (IT) and Operational Technology (OT) environments, and our preventative and detective controls through ongoing initiatives such as network modernisation, user awareness and education, identity and management as well as external assurance. Execution of the Vector cyber security strategy and roadmap has resulted in advances such as the continuous development of security orchestration, while automation has resulted in reduction of manual effort and time required to remediate security incidents as well as streamlined identification, assessment, and remediation of vulnerabilities. The network modernisation initiative has progressed and will move Vector towards a zero-trust architecture with strong foundations in privileged and service management with identity lifecycle automation for security risk mitigation, operational efficiency and visibility.

The Vector cyber security team continues to work with key global tier-1 security providers to apply a global perspective to cyber security assurance and technology, as part of an integrated Cyber Security Operating Model. We're also continuing our engagement and contribution to key New Zealand industry security forums, across public and private sectors.

The management of risk associated with cyber security is an industry wide concern. The Vector cyber security team is now working to uplift cyber security capability across the industry, by bringing together key organisations to better protect themselves and promote security awareness. A cyber security risk can come from anywhere in the world, so collaboration between partners and industry participants will provide a greater understanding of threats through intelligence and access to technologies, resources, and processes.

Vector is working continuously to improve its security posture and secure Vector's assets in this dynamic threat landscape. We have key cyber security partnerships in place and intend to further strengthen our capabilities to improve protection against increasingly frequent and complex attacks.

SECTION 07

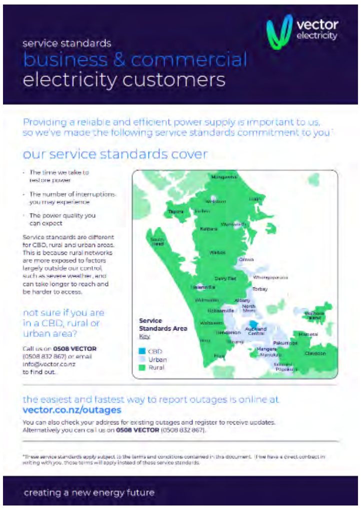
Service level targets

7 – Our service levels

This section sets out the specific service levels we measure our performance by to ensure we are delivering for our customers and stakeholders. Our service levels include regulatory targets such as SAIDI and SAIFI, as well as those we set ourselves.

7.1 Published service standards

Vector publishes on its website its service standards regarding the levels of network performance that a customer can expect on its website www.vector.co.nz. There are different standards for residential and commercial customers as well as for urban, CBD and rural. These differences reflect the different needs of customers as well as the realities of the network and surrounding geography.



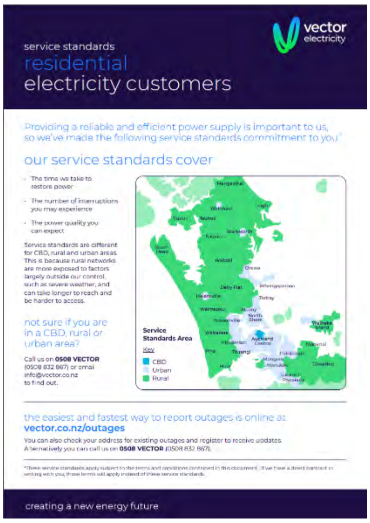


FIGURE 7.1: VECTOR SERVICE STANDARDS AS PUBLISHED ON COMPANY WEBSITE

7.2 Customer experience and customer satisfaction

7.2.1 SPEED OF QUOTES FOR NEW CONNECTIONS (SMALL CONNECTION CUSTOMERS)

DEFINITION

This service level applies to customers dealing with fewer than five lots and applies to the average time taken to quote on new connection applications. The speed of quotes for new connections is important to our customers, so we want to provide them with the information as quickly as possible.

MEASUREMENT

Measurement starts when a connection is requested and runs to the time the quote is provided.

OUR HISTORICAL PERFORMANCE

At present, 95 per cent of standard quotes are sent out within two days, and 70 per cent of quotes for non-standard connections are sent out within seven days. These measures were implemented in RY18 when standard charges were introduced for residential, 60-amp, single phase customer connections.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
Speed of quotes for new connections – Standard	-	84%	95%	93%	96%	95%
Speed of quotes for new connections – Non-standard	-	68%	85%	75%	60%	70%

TABLE 7-1: SPEED OF QUOTES FOR NEW CONNECTIONS

OUR TARGET

We aim to have 95 per cent of standard quotes sent out within two days by RY23, and 72 per cent of non-standard quotes sent out within seven days by RY23. These are reassessed every two years and we will continue this practice over the AMP period.

7.2.2 ADVANCE NOTIFICATION OF PLANNED OUTAGES

DEFINITION

To provide customers with timely, accurate and reliable notification of planned outages.

MEASUREMENT

To provide a consistent measure of the Planned Outage notification service level, Vector has aligned calculations with the requirements under the DPP3 regulatory framework relating to the notification of customers of planned outages. Vector has made several significant system and operational changes to precisely track and record exact times that customers were notified of planned outages. These notices are published on the Vector website and are sent to customers via email or paper letter based on the contact details they have provided to retailers.

These changes were implemented and measured from the start of the RY21 year.

OUR HISTORICAL PERFORMANCE

DESCRIPTION	RY21	RY22
Notified Planned Interruption Accuracy	76%	81%
Late Notice Limit	9.35%	7.14%

TABLE 7-2: ADVANCE NOTIFICATION OF PLANNED OUTAGES

The two measures are designed to measure both the accuracy of notification to customers according to the defined service levels, as well as measuring the degree of accuracy when executing on planned outages.

Notified Planned Interruption Accuracy measures the percentage of planned outages which were notified according to the target service levels and carried out to plan.

Late Notice Accuracy measures the % of planned SAIDI incurred from late notification to customers.

OUR TARGET

Under the DPP3 regulatory framework, Vector is required to give residential and commercial customers a minimum of 4 working days' notice of a planned outage, and direct billed customers a minimum of 10 working days' notice. Vector incurs additional SAIDI penalties for planned outages that are notified to customers in breach of these timeframes and which do not meet the DPP3 requirements of a "Notified Interruption". To better meet residential and commercial customer's expectations, and to allow for postage and handling delays which could impact achievement of the regulated 4 working day notice period (where applicable), Vector has chosen to adopt a target of 7 working days' notice for these customers

To best serve our customers we have adopted an overall target of:

- Notified Planned Interruption accuracy target - 80%
- Late Notified target limit - No greater than 10% of planned SAIDI to be incurred from late notification of planned outages to customers.

7.2.3 CALL CENTRE GRADE OF SERVICE (GOS)

DEFINITION

To answer all customer calls concerning faults on the network within an acceptable agreed timeframe. Our customers want to be satisfied in their dealings with us when they call.

MEASUREMENT

We use the Grade of Service (GOS) call centre measure to judge how well we are doing. The GOS measures the number of calls made to the contact centre that are answered within 20 seconds.

OUR HISTORICAL PERFORMANCE

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
Average Grade of Service (GOS)	81%	75%	79%	80%	84%	76%

TABLE 7-3: CALL CENTRE GRADE OF SERVICE

The contact centre Key Performance Metrics (KPMs) include a target for Grade of Service (GOS): 80% of calls must be answered within 20 seconds. The contact centre is incentivised to meet this, as performance against this target can impact its performance score, and subsequently its remuneration.

Vector is continuously working with our contact centre provider to improve GOS results, including increasing contact centre resource and driving efficiencies to enhance the contact centre's ability to handle high volume. We also continue to investigate self-service online capability which is at the customers' control.

Note: Some data may be excluded from GOS under a contractual Force Majeure with Telnet, covering exceptional events.

OUR TARGET

Our grade of service target is to have 80% of calls answered within 20 seconds.

7.3 Power quality

Vector publishes all service standards on its website https://www.vector.co.nz/personal/electricity/about-our-network/our-service-standards , which include regulated voltage service standards, and instructions to customers on how to contact Vector to report voltage issues.

Vector delivers supply voltages as required under the Electricity (Safety) Regulations 2010. Maintaining the network within the permissible range is getting more complex and geographically diverse. Distributed generation (e.g. solar PV) is pushing the network voltage towards the upper threshold in summer, new electric loads, such as EV charging are testing the lower threshold. In time, rapid and synchronised response of large numbers of devices to external signals, such as energy spot prices, system frequency, or time-based retailer offerings, could also cause volatility in local voltage.

We are currently developing our capability to harness power quality from smart meter data through active trials with metering equipment providers. Additionally, we are rolling out dedicated distribution transformer monitoring in areas of the network with high DER concentration and are building up pockets of low voltage network with high visibility. This helps complement smart meter data and the case study below illustrates how both data sets are used.

We are continuing to take the two following approaches to managing power quality, to work around a lack of access to customer smart metering data. Firstly, we have an active programme to install power quality meters (PQMs) at several our zone substations and GXP sites to monitor the network and secondly, we take a reactive approach to investigate any incidents identified by customers.

Vector has installed PQMs to primarily baseline and trend harmonic [1] levels on the network. This is especially helpful to us in monitoring and understanding the impact of power electronics operating at the residential level, particularly the increasing numbers of inverters associated with solar PV, electric vehicle, and battery charging. This also enables us to proactively address any power quality issues we identify.

When we are notified of instances of the network operating outside the regulated voltage range, we investigate and then remedy the problem. The data from PQMs is analysed to determine the cause of any network disturbances, and changes made to improve our performance to meet regulatory requirements.

The power quality requirements are summarised as:

- Electricity Safety Regulations requires that Low Voltage must remain within 6% of the nominal voltage (230V for single phase)
- Electricity Industry Participation Code Part 8 requires that High Voltage must remain within 6% of the nominal voltage
- AS/NZSS 61000 and its Parts sets out the requirements for voltage and current waveform distortions
- Voltage and frequency requirement for distributed generation (customer connections) are set out Vector's website

7.3.1 IMPROVING PRACTICES FOR MONITORING LV NETWORK VOLTAGE QUALITY

Vector's current practice regarding voltage services levels is to respond reactively to all customer reports of voltage issues. These are promptly investigated and where they relate to the quality of voltage at the customer's point of supply, are resolved by reconfiguring or upgrading the distribution network.

Vector has two key initiatives to improve visibility of the LV network, and specifically provide greater visibility of LV voltage. These two initiatives will allow Vector to proactively monitor customer LV network voltage quality, which is a step change from currently reacting to customer reports.

1) Distribution transformer LV monitoring
Vector is undertaking a programme of work to install power quality instrumentation on up to 10% of its distribution transformer fleet. This will provide highly precise measurement of LV Feeder and LV Phase voltage performance. This data will be available in near-real-time and can be used to proactively identify and respond to voltage performance issues.

2) Smart meter power quality data
Vector is actively engaged with the two primary Metering Equipment Providers (MEPs) on the network to obtain comprehensive power quality data from smart meters installed on the network. By RY24 Vector is anticipating that it will have access to smart meter data which includes voltage, recorded at 30 minute or 5-minute intervals, for up to 30 per cent of the ICPs on the network. Access to this data will provide a substantial improvement of Vector's ability to monitor the performance of the LV network as recorded at the customer's meter. This data will enable Vector to identify individual ICPs, as well as LV circuits and individual LV Phases experiencing voltage issues and will enable Vector to proactively respond and resolve issues. Additionally, this data will enable Vector to identify the potential root cause of voltage issues, such as unregistered or non-compliance DER installations, or increased EV density.

[1] Harmonics occur on the network when current and voltage are distorted and deviate from sinusoidal waveforms. Harmonic currents are caused by non-linear loads connected to the distribution system

CASE STUDY: SMART METER POWER QUALITY AND DISTRIBUTION TRANSFORMER

Vector has actively trialled the use of distribution transformer monitoring equipment and power quality data from smart meter data to gain visibility into the LV part of the network, which traditionally has been built to 'fit and forget'. Distribution transformer monitoring has the advantage of directly monitoring each phase of an LV circuit but cannot provide a granular perspective at the ICP level. Modern smart meters can provide detailed power quality data (current, voltage, phase angle) at the ICP level when combined with LV network topology and asset information, but this capability is not available on all deployed smart meters in the Auckland fleet.

This trial will help visualise the difference between smart meter and monitoring equipment. For this example, it is worth noting as well that voltage levels are breached during short instances overnight when demand is low. This was not anticipated as the focus of the business is to keep voltage level with limits during the day and, in the absence of data, respond based on customer complaints. The learning here is that as EDBs gain visibility on LV voltage, we will be able to assess compliance against actual data and could identify issues that are unknown today. Figure 7-2 below illustrates how smart meter data can be used to provide greater insight into transformer performance.

As the number of devices responding to external signals increases, predicting patterns of demand and flow on our network will become increasingly complex. In this environment, maintaining voltage within the narrow band of existing statutory limits will require more localised control and investment, which will not be in the long-term interest of consumers. A wider range of permissible voltage will create much more flexibility both for EDBs and the owners and operators of DERs.

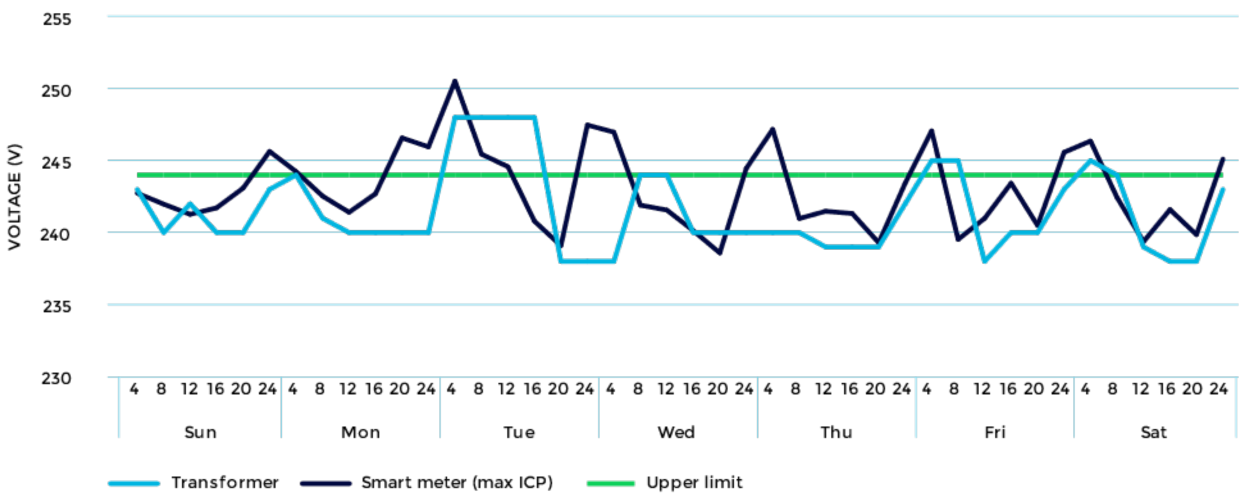


FIGURE 7.2: VOLTAGE DATA FROM TRANSFORMER MONITORING EQUIPMENT COMPARED TO ICP-LEVEL SMART METER DATA

ADDRESSING KNOWN NON-COMPLIANCE

If any voltage non-compliance issues are identified from customer complaints and confirmed by data, then a technical investigation will ensure that the issue is not created by poorly configured customer-side equipment (e.g. induction motors or inverters) and will then identify the most suitable solution to address the issue. Typical solutions to address power quality constraints include alternating the tap change on the transformer, reconfiguring the network, reconductoring the line or upgrading the transformer.

RESPONDING AND REPORTING

Vector responds reactively to all stakeholder reported voltage issues. All reported issues are recorded as a voltage investigation service requests in our CRM system Siebel. These may be identified by our customers or by our field service providers.

The customer resolutions team manage the resolution of all investigation requests. Initially an investigation will be conducted into the nature of the issue. Typically, this will result in an on-site investigation, and a power quality logger will be installed and run for a minimum of 1 week to log the power quality at the point of supply. If the investigation request relates to a customer's specific appliance, then Vector may install a separate logger on the appliance to determine whether the issue relates to the Vector supply, or the customer's installation.

COMMUNICATING TO CUSTOMERS

All voltage investigations are dealt with by the customer resolutions team. A representative will contact customers directly using email or telephone. The customers will be informed of all work being undertaken on the network to address voltage issues.

7.4 Safety

Each year Vector undertakes millions of work activities without harm. We are thinking of safety differently and building our understanding of the success factors required to achieve safe work by broadening our focus from TRIFR and LTI's (lag indicators which have limitations and record unwanted outcomes) to put increased focus on forward looking lead indicators which measure activities which are done right every day. Vector is using a Safety II approach where this can increase health, safety and wellbeing across our work activities and our key focus remains on our critical risks and the effectiveness of the controls we rely on to manage these risks. We continue to place significant emphasis on the management of our outsourced field service providers, and the assurance of the quality of their health and safety systems and practices.

7.4.1 LEAD INDICATORS FOR SAFETY MEASUREMENT

DEFINITION

Leading indicators focus on the organisation's future health and safety performance with the intent of embedding continuous improvement. They are a signal and monitor of what is being done on an ongoing basis to prevent adverse health and safety outcomes.

MEASUREMENT

To be effective, lead indicators must be linked to safety outcomes the organisation wants to see (where there is evidence of a clear link between cause and effect) e.g. where measurement of number of safety risk toolbox meetings before work starts on site has seen a reduced number of safety incidents on site. Lead indicators will measure safety actions and introduce accountability for safety before people get harmed.

7.4.2 TOTAL RECORDABLE INJURY FREQUENCY RATE

DEFINITION

The total recordable injury frequency rate (TRIFR) encompasses all network incidents resulting in medical treatment, restricted work injury, lost time injury or fatality, which impacts Vector people including all contractors and FSPs.

MEASUREMENT

The incident count is divided by the number of hours worked for the same measurement timeframe, Vector reports TRIFR as a rolling 12-month average which is then normalised to report TRIFR in per million hours worked.

HISTORICAL PERFORMANCE

Table 7-4 shows the Networks TRIFR performance under the definition of this service level metric.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
Total recordable injury frequency rate (TRIFR)	5.28	14.07	5.01	5.82	7.45	6.25

TABLE 7-4: TRIFR

7.4.3 ASSET SAFETY INCIDENT MEASURE

DEFINITION

The asset safety incident measure is a count of incidents that resulted in harm to personnel, members of the public or to property, resulting from a deficiency or failure in any equipment on Vector's electricity distribution network.

MEASUREMENT

The asset safety incident measure is calculated by identifying the number of asset safety incidents in Vector's Risk and Incident Management System (ARM) which have caused harm or damage to people or property.

HISTORICAL PERFORMANCE

Table 7-5 shows the asset safety incident performance following the definition of this service level metric.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
Asset safety incident	1	7	5	4	0	1

TABLE 7-5: ASSET SAFETY INCIDENTS

The number of asset safety incidents has further reduced in RY21 and RY22. For RY22, the single incident related to a LV flashover incident. The flashover injury resulted from a deviation from standard work practices and processes whilst investigating a fault and removing a live fuse carrier. The resulting injury was minor.

7.5 Reliability

This considers the ability of the network to deliver electricity consistently when demanded under normal design conditions. We are committed to achieving compliance with the Regulatory quality metrics.

7.5.1 PROVIDING NOTICE AND COMMUNICATION OF PLANNED AND UNPLANNED INTERRUPTIONS TO CUSTOMERS

PLANNED OUTAGES

Ahead of all planned outages Vector conducts an extensive assessment of the customers to be affected. In particular, careful consideration is given to the operating hours of affected businesses and organisations such as churches and schools, and wherever possible Vector will adjust the schedule of planned outages to reduce the effect on customers. If necessary, Vector will contact customers directly to discuss scheduling.

Vector directly notifies customers of scheduled planned outages via Letter and/or Email, depending on the availability of email contact information provided from the retailers. Vector also sends SMS reminders for notified planned outages to customers that have valid mobile numbers. Vector has a target service level for sending direct notice to customers a minimum of 10 working days in advance of the notified planned outage. It is worth noting that the quality and availability of data for communicating to customers directly via electronic mechanisms (email and SMS) is dependent on data supplied to Vector by the customer's retailer. Where this has not been supplied to Vector, a physical letter is mailed to the customer's postal address and the physical address of the property affected (should they be different).

For planned outages that impact 20 customers or fewer (excluding direct-billed customers), Vector's field service provider has the option to Card Drop the outage notice directly to the customers mailbox at least 4 working days in advance of the outage.

Notice for postponement of a notified planned outage must be given to customers at the earliest convenience and is only allowed if the customer was notified of alternate dates and times on the original outage notice. Vector's target is to have customers informed of postponements prior to the proposed original start time.

Notice for cancellation of a notified planned outage must be given to customers at the earliest convenience. Vector's target is to have customers informed of cancellations at least 24 hours prior to the proposed notified start time.

All scheduled planned outage information is also published on Vector's website via the Outage Centre *https://help.vector.co.nz/planned* . This service allows customers to search an address to see upcoming planned outages. Customers can also view a map of Auckland to see planned outages currently being executed.

Improvements recently made to planned outage communications is the ability to send planned outage overrun notices directly to customers who have email/ SMS contact information, at times where outages unexpectantly take longer than originally notified. This will help to manage customer expectations when outages do not go to plan.

UNPLANNED OUTAGES

Vector has several channels for communicating to customers about unplanned outages. These are outlined below:

1. Website – Outage Centre

All known unplanned outages are shown on Vector's website https://help.vector.co.nz/address. Customers can either check their address or view a map of the Vector network to identify and track the status of known unplanned outages. Customers can also use the Outage Centre to report an outage if it is not currently displayed.

The Outage Centre is Vector's primary channel for providing interactive updates to customers on the progress of unplanned outage restoration. Customers can subscribe to receive SMS or email updates on the restoration progress of an unplanned outage. Wherever possible an estimated time of when the power will be restored is posted along with the reason of why the outage happened.

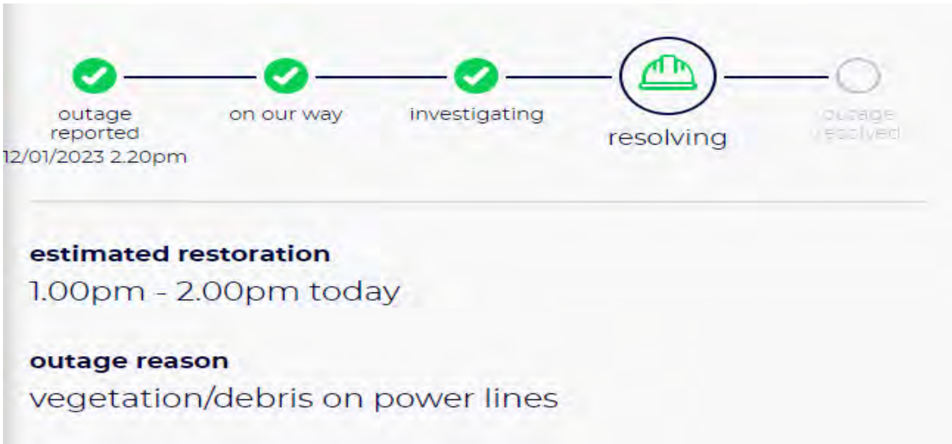


FIGURE 7.3: VECTOR'S WEBSITE OUTAGE CNETRE NOTIFICATION

2. SMS / TXT messaging

Should an unplanned outage occur which affects one or more high voltage feeder circuits, all affected customers, who have provided their electricity retailer with a valid mobile telephone number, are sent an SMS message detailing the nature of the fault and expected restoration time.

3. Call Centre & IVR

Vector operates a 24 x 7 call centre using the telephone number 0508 VECTOR or 0508 832 867. The call centre provides the ability for customers to report unplanned outages, as well as get updates on the status of current unplanned outages via a call centre operator. In addition, an Interactive Voice Response (IVR) tool is integrated with the call centre, which provides automated verbal updates on known unplanned outages to customers and redirects customers to the Outage Centre. The IVR minimises customer call waiting times during time of high call numbers.

4. Social Media

Before and during large scale events (such as a storm) with multiple unplanned outages, Vector will communicate to customers using social media.

5. Bespoke communications

Where a specific group of customers requires targeted communication due to the nature or duration of a specific unplanned outage, Vector will deliver targeted bespoke communications. These are in the form of an email or SMS.

We are committed to keeping our customers informed when unplanned outages occur, and we constantly drive improvements in making this happen. Improvements recently made to communicate unplanned outages is the ability for our field service providers to provide additional information if they are unable to provide timely ETRs. Other planned initiatives are to increase proactive messaging on progress updates, and to ensure the progress updates provided are timely, informative and set the right expectations.

7.5.2 SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

DEFINITION

SAIFI measures the average number of outages per customer per RY, the value expressed in the number of interruptions. This is one of the key metrics used to assess the reliability of the network. It is calculated as the total number of customer interruptions divided by the total number of customers served, where interruptions are for 1 minute or longer.

In order to align with information disclosure requirements set out under the electricity distribution service default price-quality path determination (DPP3), from RY21 Vector has moved to measuring planned and unplanned SAIFI as two separate measures, with respective targets.

It is noted that Vector does not record SAIFI according to the 'successive interruption method' as defined in the 2022 Targeted Information Disclosure Review.

MEASUREMENT

SAIFI= (total number of interruptions) / (average number of customers)

SAIFI only measures outages caused by an event on the HV network and does not include the LV network. Unplanned SAIFI is limited where a major event has occurred (e.g. storms), to prevent these extreme events from distorting the overall SAIFI data. The following formula is used for the planned SAIFI calculation:

$$SAIFI\ planned, assessed\ = SAIFI_B$$

Where:

$SAIFI_B$ is the sum of the SAIFI values:

(a) for Class B interruptions commencing within the assessment period.

The following formula is used for the unplanned SAIFI calculation:

$$SAIFI\ unplanned, assessed\ = SAIFI_C$$

Where:

$SAIFI_C$ is the sum of the SAIFI values:

(a) for Class C interruptions commencing within the assessment period, where the SAIFI value for each 30 minute period that starts on the hour or half past the hour within a SAIFI major event that exceeds 1/48th of the SAIFI unplanned boundary value for that assessment period is replaced with 1/48th of the SAIFI unplanned boundary value for that assessment period.

The SAIFI Unplanned Boundary Value is calculated as per the Commerce Commission process. This limit is set to 0.037 for the current regulatory period (1 April 2020 to 31 March 2025).

Class B interruptions - means planned interruptions by a non-exempt EDB

Class C interruptions - means unplanned interruptions originating within the system fixed assets of a non-exempt EDB

All of Vector's interruption data is held in our HV Spec database which is used to calculate and report on SAIFI performance. SAIFI is continually monitored including reporting to the Strategic Reliability Management (SRM) fortnightly meeting and reported on a monthly and annual basis to inform asset management practices. For regulation purposes, SAIFI is reported to the Commerce Commission on an annual basis. SAIFI reporting to the Commerce Commission is subject to an external audit.

The SAIFI target is set by the Commerce Commission's regulatory determination every 5 years. It is largely based on the average SAIFI performance over a 10-year historical Reference Period. The process for setting this target is specified in the DPP Determination.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
SAIFI – Combined	1.85	2.14	1.76	1.58		
SAIFI – Planned					0.342	0.269
SAIFI – Unplanned					1.070	1.048

TABLE 7-6: SAIFI

For the 2022 assessment period, Vector did not exceed its reliability limits and was compliant with the DPP3.

Vector considers the matter of quality compliance of utmost importance. To improve our network reliability, we have invested significantly in network improvements and operational processes to improve network reliability.

TARGET

For the Regulatory Period, (1 April 2020 to 31 March 2025) Vector's annual SAIFI target has been set based on the limits defined within the DPP3. It is worth noting that from 1 April 2020 these targets have been split according to Planned and Unplanned events.

Unplanned SAIFI Limit = 1.337

Planned SAIFI Limit = 0.576 (Average annual)

(refer to the DPP3).

7.5.3 SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

DEFINITION

The SAIDI index measures the average duration of outages per customer per RY, the value is expressed in minutes. This is one of the key metrics used to assess the reliability of the network. It is calculated as the sum of the duration of all customer duration interruptions divided by the total number of customers served, where interruptions are for 1 minute or longer.

In order to align with information disclosure requirements set out under the DPP3, from RY2021 Vector has moved to measuring planned and unplanned SAIDI as two separate measures, with respective targets.

MEASUREMENT

SAIDI = (total interruption minutes) / (average number of customers)

SAIDI only measures outages caused by an event on the High Voltage (HV) network and does not include the LV network. The SAIDI dataset is normalised using a process defined by the Commerce Commission in the DPP. This process reduces notified planned interruptions by 50% as it is considered that customers are less impacted by interruptions that are planned. It also limits unplanned SAIDI on days where a major event has occurred (e.g. storms) to prevent these extreme events from distorting the overall SAIDI data. The following formula is used for the planned SAIDI calculation:

$$SAIDI\ planned, assessed\ = SAIDI_B + \frac{SAIDI_N}{2}$$

Where:

$SAIDI_B$ is the sum of the SAIDI values:

(a) for any Class B interruptions commencing within the assessment period that are not Class B notified interruptions; and

(b) in respect of any Class B notified interruptions commencing within the assessment period that have occurred partially or wholly outside of their specified notified interruption window or alternate day, the SAIDI value attributable to the period of minutes that falls outside of that specified notified interruption window or alternate day.

$SAIDI_N$ is the sum of:

(a) the SAIDI values attributable to any minutes that fall within the specified notified interruption window or alternate day of any Class B notified interruptions commencing within the assessment period, where the SAIDI value is the greater of that calculated based on:

(i) the duration of minutes accumulated for each ICP that the Class B notified interruption occurred for; and

(ii) the period of the notified interruption window minus two hours;

(b) the 'intended SAIDI values' of any intended interruption cancelled without notice in the assessment period, where the 'intended SAIDI value' for each of those intended interruptions cancelled without notice is the greater of that calculated based on:

(i) the duration of minutes accumulated for each ICP that the intended interruption occurred for, which will be nil; and

(ii) the period of the notified interruption window minus two hours; and

(c) the 'intended SAIDI values' of any intended interruption cancelled with notice in the assessment the period, where the 'intended SAIDI value' for each of those intended interruptions cancelled with notice is nil.

The following formula is used for the unplanned SAIDI calculation:

$$SAIDI\ unplanned, assessed\ = SAIDI_C$$

Where:

SAIDIc is the sum of the SAIDI values:

(a) for Class C interruptions commencing within the assessment period, where the SAIDI value for each 30 minute period that starts on the hour or half past the hour within a SAIDI major event that exceeds 1/48th of the SAIDI unplanned boundary value for that assessment period is replaced with 1/48th of the SAIDI unplanned boundary value for that assessment period.

The SAIDI Unplanned Boundary Value is calculated as per the Commerce Commission process. This limit is set to 4.83 for the current regulatory period (1 April 2020 to 31 March 2025).

Class B interruptions - means planned interruptions by a non-exempt EDB

Class B notified interruption - means a Class B interruption that a non-exempt EDB has given additional notice for, and the Class B interruption is recorded as a 'Class B notified interruption' in the non-exempt EDB's internal systems

Class C interruptions - means unplanned interruptions originating within the system fixed assets of a non-exempt EDB

All of Vector's interruption data is held in our HV Spec database which is used to calculate and report on SAIDI performance. Supply interruptions are identified by the Supervisory Control and Data Acquisition (SCADA) system or through calls to the Customer Excellence team. Once faults have been resolved by the FSP, details of interruptions are logged in HV Spec. The customer interruptions are updated as supply is restored, with SAIDI calculated for each step in the restoration process. Where faults are identified through the Customer Excellence team, details are also captured in Siebel and linked back to HV Spec. SAIDI is continually monitored including reporting to the SRM fortnightly meeting and reported on a monthly and annual basis to inform asset management practices. For regulation purposes, SAIDI is reported to the Commerce Commission on an annual basis. SAIDI reporting to the Commerce Commission is subject to an external audit.

The SAIDI target is set by the Commerce Commission's regulatory determination every 5 years. It is largely based on the average SAIDI performance over a 10-year historical reference period. The process for setting this target is specified in the DPP.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
SAIDI – Combined	173.6	226.2	198.2	167.5		
SAIDI – Planned					46.54	40.48
SAIDI – Unplanned					86.3	92.42

TABLE 7-7: SAIDI

For the 2022 assessment period, Vector did not exceed its reliability limits and was compliant with the DPP Determination.

Vector considers the matter of quality compliance of utmost importance. To improve our network reliability, we have invested significantly in network improvements and operational processes to improve network reliability.

TARGET

For the Regulatory Period, (1 April 2020 to 31 March 2025) Vector's annual SAIDI target have been set based on the limits defined within the DPP3. It is worth noting that from 1 April 2020 these targets have been split according to Planned and Unplanned events.

Planned SAIDI Limit = 117.08

Unplanned SAIDI Limit = 104.83

(refer to the DPP3).

7.5.4 NUMBER OF CUSTOMER INTERRUPTIONS PERFORMANCE AGAINST AGREED SERVICE STANDARDS

DEFINITION

This service level measures the number of unplanned supply interruptions experienced by customers on Vector's distribution network. It differs from SAIFI as it is the actual number of interruptions that a customer experiences rather than the average across the network. As with SAIFI, the interruptions are those of 1-minute duration or greater. At this stage, this metric only includes outages on the HV network. We see this measure as a much more effective representation of the impact of outages on customers, than an average measure such as SAIDI, that enables us to effectively engage customers affected by outages on issues such as cost quality trade-offs, etc.

The Use of System Agreements between Vector and energy retailers and Vector's Service Standards for Residential and Business & Commercial Electricity Consumers define the standard for customer interruptions. The standard states the number of interruptions, longer than 1 minute, that a consumer experiences per year should not exceed:

- 4 interruptions per annum in the CBD and urban areas; and 10 interruptions per annum in rural areas.

MEASUREMENT

All of Vector's interruption data is held in the HV Spec system, which is used to calculate and report on the number of customer interruptions performance. This metric is measured on an annual basis.

DESCRIPTION	RY17	RY18	RY19	RY20	RY21	RY22
Customer interruptions performance	96.6%	92.6%	97.1%	97.3%	98%	98.6%

TABLE 7-8: CUSTOMER INTERRUPTIONS PERFORMANCE

The number of customer interruptions exceeding the agreed service. standards has decreased over the past year. The factors affecting these measures are similar to those affecting Vector's SAIDI and SAIFI service standards, however, these service standards do not include any events outside of Vector's direct control (such as storms or third-party damage to the network).

TARGET

Vector's target is to meet or exceed 99% compliance.

7.6 Security of supply

Security of supply of the electricity network is the ability of the network to meet customer demand without interruption. Security of supply needs to balance the cost of redundancy with customer expectations and the benefit of supply availability for customers and society. The benefit for customer and society is progressively changing and in general increasing due to the growth of the service economy, electrification of transport and heat, and increased remote working arrangements.

Security of supply specifies the network capability for restoring power after single or multiple asset failures (unplanned outages) and maintenance (planned outages). The general principle is that the higher the network level, the more demand is at risk from a single event, and the stricter the requirements to provide demand restoration before the fault(s) are repaired. The reliability metrics SAIDI and SAIFI are closely related to security of supply. These metrics measure asset performance and outage management across the network (for assets ≥11 kV), while the SoS defines network architecture and restoration requirements (including redundancy of assets).

Vector uses a probabilistic approach in the security of supply standard (ESP010). These are based on nine categories, classified according to sub-transmission, distribution and CBD or non-CBD, as shown in Table below. Very importantly, the SoS standard sets the criteria for network development about when and where reinforcement is needed.

CLAUSE	DEMAND	CATEGORY	STANDARD
1	Any	Single events incurring greater than 4 SAIDI minutes	>4 SAIDI minutes: investment evaluated using a risk-based approach
2	Any	CBD ZSS and sub-transmission	N-1: All demand (first contingency – no interruption) N-2: All demand (second contingency – restored in 2 hours)
3	Any	Non-CBD ZSS and sub-transmission	N-1: All demand restored in 2.5 hours (urban), 4.5 hours (rural). This requirement to be met for 95 percent of the year for primarily residential substations and 98 percent of the year for primarily commercial substations
4	Any	CBD distribution feeders (22 kV or 11 kV)	Demand restored to all but a single distribution substation in 2.0 hours. Remainder restored in repair time
5	Any	Non-CBD distribution feeders (22 kV or 11 kV)	Primarily underground: demand restored to all but 800 kVA within 2.5 hours (urban). Remainder restored in repair time Primarily overhead: Demand restored to all but 2.5 MVA within 2.5 hours (urban) and 4 hours rural. Remainder restored in repair time. This requirement to be met for 95 percent of the year for primarily residential feeders and 98 percent of the year for primarily commercial feeders
6	Any	Distribution substations (11/0.4kV)	Restored within repair time
7	Any	Distribution feeders (400V or 230V)	Restored within repair time
8	Any	All sub-transmission and zone substations	Maximum of one month on security reduced with respect to clause 2 and 3
9	Any	All sub-transmission and zone substations	Spatial separation of primary network assets sufficient to avoid common mode failure

TABLE 7-99: SUMMARY OF SOSS

7.7 Cyber Security

As our electricity network continues to evolve greater digital capability is built to deliver customer benefits, we are committed to investing in technology solutions, processes and capabilities to ensure that we appropriately protect and detect potential disruptive security events that could impact customer privacy or our network services. The threat of a successful attack is ever-present, and we can therefore no longer solely rely on detective and preventative controls to mitigate the risk. Robust recovery strategies are also required to be able to quickly respond and recover to limit the impact.

While our ability to meet any service targets is highly dependent on the nature and complexity of each attack we have set ourselves clear performance targets for the detection, containment and recovery from a cyber security incident. Effective processes and procedures have been developed to ensure our service targets can be met (or where possible exceeded) and

Vector is very committed to achieving these. A description of the service levels is included below however, we do not publish the actual service level targets due to commercial sensitivities and for security reasons.

The table below summarises how we prioritise security incidents for our environment:

PRIORITY	DESCRIPTION	NARRATIVE
1	Critical Incident	Under Attack or Threat. Vulnerabilities are being exploited with a high level of damage or disruption, or the potential for severe damage or disruption is high and will have a severe impact on business operations and/or damage, disruption of Critical Infrastructure Assets.
2	Priority Incident	The real potential exists for malicious cyber activities due to exploits that have been identified or known exploits that have been identified that may indicate an advanced persistent threat. Or intelligence has been gained that a significant event may occur.
3	Standard Incident	Some disruption to business systems or users or customers may be experienced due to a cyber event, but does not impact any major services, or known exploits have been identified but no significant impact has occurred.
4	Low-Impact Incidents/ Request for Service	An incident that allows the Infrastructure or Client system to be used with limited functions and has a low risk of significant business impact. This also covers requests for service – i.e. not logging an Infrastructure fault. This typically comprises a change request but may also include requests for information.

TABLE 7-10: INCIDENT PRIORITY DEFINITIONS FOR CYBER SECURITY

7.7.1 INCIDENT AND REQUEST SERVICE LEVELS

SERVICE LEVEL NAME	SERVICE LEVEL
Incident Management Incident Response	P1: 90% of P1 Incidents responded to within 2 hours P2: 90% of P2 Incidents responded to within 4 hours P3: 90% of P3 Incidents responded to within 8 hours P4: 90% of P4 Incidents responded to within 8 hours
Incident Management Incident Response	P1 incident reports for service impacting events issued as and when agreed for the specific event
Request Fulfilment	90% of Service Requests are actioned within 5 business days

TABLE 7-11: INCIDENT AND REQUEST SERVICE LEVELS

7.7.2 INCIDENT SUPPORT HOURS

SEVERITY	SUPPORTED HOURS
1 – Critical Incident	24x7
2 – Priority Incident	24x7
3 – Standard Incident	Business Hours
4 – Request for Service	Business Hours

TABLE 7-12: INCIDENT SUPPORT HOURS

SECTION 08

Network maintenance

8 – Network maintenance

8.1 Section overview

This section describes the key elements of Vector's approach to the maintenance of our network assets. These activities are crucial to ensuring that the assets are well maintained and can continue to operate safely and effectively while delivering to our Asset Management Objectives.

Vector's maintenance portfolio covers a broad spectrum of activities and includes investment across both OPEX and CAPEX profiles. The key elements of the portfolio include Planned Maintenance, Corrective Maintenance, Reactive Maintenance and Vegetation Management.

We continue to focus on our risk based approach to corrective maintenance and vegetation management as we further refine these to continue to drive efficiencies in the medium to longer term.

As maintenance is the primary source of ongoing asset condition information, the ongoing benefits from the improvements from our systems and standards changes will allow us to become more predictive and risk based in our overall approach. This will support our longer-term Condition Based Asset Risk Management (CBARM) modelling initiatives and associated asset lifecycle decision making.

8.2 Network maintenance activity overview

The key elements of our network maintenance program are as follows:

Planned Maintenance (PM) – this activity delivers our routine maintenance programme for inspections, condition assessments, testing and servicing of our assets in accordance with our maintenance standards.

Corrective Maintenance (CM) – this activity primarily addresses issues identified through our condition-based assessments and inspections. Functionality is restored, and assets are repaired or replaced as required to ensure that the network can continue to operate safely and effectively.

Reactive Maintenance (RM) – this activity primarily focuses on restoration of supply when a fault or other network incident occurs. Reactive maintenance incorporates our faults response and the remediation work needed to restore supply.

Vegetation Management – this activity focuses on the management of vegetation to ensure our assets can continue to operate safely and effectively.

8.3 Asset management objectives

The Asset Management Objectives that are addressed through our network maintenance activity and investments are set out in the table below:

FOCUS AREA	OBJECTIVES
Safety, Environment and Network Security	• Prevent harm to workers, contractors and the public through our work practices and assets. • Ensure health and 'safety always' is at the forefront of decision making for the business. • Comply with relevant safety and environmental legislation, regulation, and planning requirements. • Asset management activities align with environmentally responsible and sustainable behaviours, in line with industry best practice, enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices.
Customers and Stakeholders	• Provide a high-quality customer service experience across all interactions. • Listen to and learn from our customers to ensure our service offering aligns with customer expectations. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times.
Network Performance & Operations	• Comply with regulatory quality standards set out in the DPP3 Determination. • Maintain accurate and comprehensive information management systems to drive continuous improvement of our asset health database and information records and meet regulatory reporting obligations. • Continual improvement of our asset management system and alignment to ISO 55001. • Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact-based investment profiling. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings. • Manage performance of field service providers through effective commercial arrangements and regular review.

FOCUS AREA	OBJECTIVES
Future Energy Network	• Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Improve our visibility of, and ability to control, the LV network including management of the information required.

TABLE 8-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

8.4 Planned maintenance

8.4.1 OVERVIEW

Planned Maintenance is carried out periodically on all of Vector assets to ensure they can continue to operate safely and effectively, to ensure reliability and resilience of the network and to maximise the service life of our assets. Our program of planned maintenance also gathers important asset condition information which is a primary input into our predictive asset strategies and replacement plans and ensures compliance with regulatory requirements.

Vector has a suite of maintenance standards which are a key control in managing the risks associated with all our assets. These documents define the specific requirements and schedules for inspections and servicing for each type of asset in service.

The main type of activities conducted during Planned Maintenance are:

- **Functional Inspections** – regular inspections and patrols ensure the integrity of the network and focus on identifying issues that may have a more immediate impact on safety and reliability. Functional inspections are our most frequent asset inspections and primarily feed into Vector's corrective maintenance regime.
- **Servicing and Testing** – maintenance tasks that are performed on an asset in accordance with our maintenance standards to ensure that our assets can continue to operate safely and effectively.
- **Full Inspections** – inspections that primarily record detailed asset condition information that is used to support our predictive asset strategies and analysis.

8.4.2 PLANNED MAINTENANCE OBJECTIVES

We have identified the following objectives to guide our Planned Maintenance programme.

ASSET MANAGEMENT OBJECTIVE	PLANNED MAINTENANCE PORTFOLIO OBJECTIVE
Safety, Environment and Network Security	Ensure that our planned maintenance regime is an effective control for the risks associated with owning and operating a network and our commitments to the environment and public safety are not compromised.
Customers and Stakeholders	Minimise planned outages to our customers by grouping and prioritising works effectively, and where economically practical use generation to reduce planned interruptions.
Network Performance & Operations	Asset Reliability - Maximise asset life and improve reliability by ensuring that planned maintenance is completed in accordance with our maintenance strategies. Monitor asset performance and reliability and review our planned maintenance requirements to ensure they are up to date. Operational Efficiency - Ensure that our planned maintenance requirements and expectations are clearly defined, and our supporting systems are configured to reflect this. This ensures that our delivery resources can focus on delivery and improving efficiency. Asset Lifecycle Information - Ensure that asset lifecycle and condition assessment information is recorded through our planned maintenance activities. Ensure that our asset data sets are consistent, complete and are of a high quality to support our predictive and risk-based asset strategies.

TABLE 8-2: PLANNED MAINTENANCE OBJECTIVES

8.4.3 PLANNED MAINTENANCE IMPROVEMENT INITIATIVES

We seek to continuously improve our approach to asset management and maintenance. The initiatives presented below are targeted at improving our planned maintenance programme.

INITIATIVE	DESCRIPTION
New Maintenance Standards	New Maintenance Standards are being introduced to define the requirements for Ripple Injection Plant, Battery Energy Storage Systems, Mobile Substation Contingency Plant and Power Transformers in Storage to enable these requirements to be systemised into SAP, like all other network assets.
CBM - Switchgear	Implementation of a new condition-based maintenance (CBM) regime for primary and overhead switchgear to supplement some of the existing time-based planned maintenance actions.
Continuous Improvement	Network risks and asset strategies are reviewed periodically to ensure that are aligned with Vectors network performance expectations and proposed changes to planned maintenance requirements are collated into a register for implementation into the maintenance standards.

TABLE 8-3: PLANNED MAINTENANCE IMPROVEMENT INITIATIVES

8.4.4 PLANNED MAINTENANCE OPEX FORECAST

Our Planned Maintenance expenditure forecast is presented in Figure 8.1. The forecast incorporates changes to our planned maintenance activities through the introduction of our new maintenance standards and the introduction of new initiatives that are aimed at increasing our condition assessment knowledge base. As a result of the system changes implemented previously and our improving maturity, PM forecasts are now produced using the actual schedules in SAP associated with each specific asset, improving the integrity of the forecast.

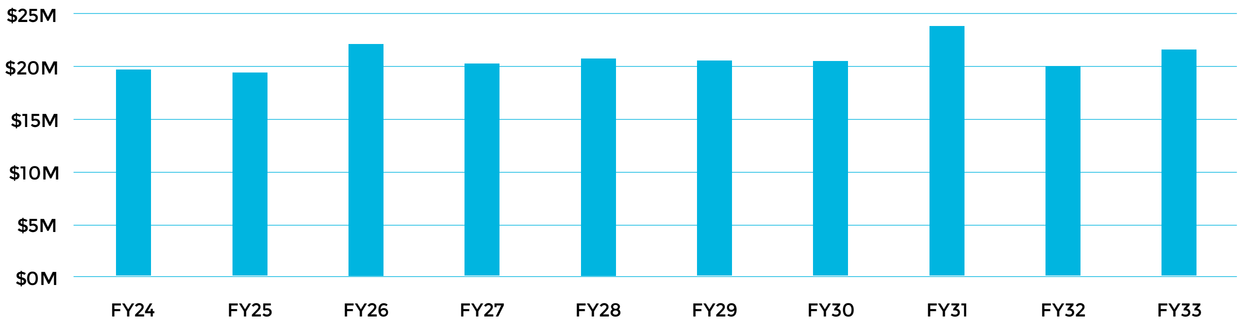


FIGURE 8.1: PLANNED MAINTENANCE OPEX EXPENDITURE FORECAST

8.5 Corrective maintenance

8.5.1 OVERVIEW

Corrective Maintenance is the action to restore and renew functionality of our assets before they fail by remediation of condition issues predominantly identified through our planned maintenance activities. These actions are crucial to ensure the assets can continue to perform their intended function safely and reliably. Corrective Maintenance activities assist with extending the service life of assets without compromising our performance expectations and are complementary to our pro-active CBARM driven asset replacement initiatives.

Vector's risk-based approach and other SAIDI related initiatives, including proactive CBARM asset replacement introduced in prior periods, continues to be a focus.

Our corrective investment can be broken down into the following key areas.

- **Corrective Maintenance Repairs** – These are minor corrective works undertaken to restore assets to a safe and functional state. These activities are classified as OPEX.
- **Corrective Asset replacements** – These are corrective asset replacements that are undertaken to ensure that the network can continue to operate safely and reliably without compromising performance. These activities are classified as CAPEX.

Vector has taken a holistic approach to corrective maintenance and has developed the necessary capability to plan and optimise this work using a full risk-based approach enabled by the system improvements introduced by SAP PM in RY21, which is described in more detail below. This means that work can be planned and executed at a TOTEX level. These systems and methodology have enabled capability that allows our field service providers (FSPs) to easily select and assemble packages of work that minimise outage disruptions for our customers while maximising the reduction in risk. Together, they enable dynamically optimised corrective work planning and delivery.

8.5.2 RISK BASED APPROACH (RBA)

A more comprehensive Risk Based Approach (RBA) to corrective work, introduced in RY21 as a part of our introduction of the SAP PM module, is a significant step forward in our asset management capability, introducing the ability to better prioritise the delivery of corrective work.

The RBA is complementary to our longer term pro-active CBARM driven initiatives and focuses on addressing risks that are more immediate. Under the RBA we now calculate a specific risk score for each notification which incorporates weightings for the potential financial, safety, environmental and customer impact (SAIDI consequence). These values are refreshed daily and designed to reflect each notification's relative risk at that time. This is a dynamic process which considers environmental changes, network reconfiguration, and changes to notification likelihood, as well as reflecting the current status of the notification pool to include any new notifications as well as those removed or changed.

The RBA methodology uses the calculated risk score value and network section identification information on each notification. Together, this enables the corrective planning teams to always focus on the notifications with the highest risk and develop and optimise work packs by incorporating other open high-risk notifications that can be completed during the same planned outage on the affected network sections. This reduces the number of outages our customers experience and improves the efficiency of delivery. The methodology provides Vector with a corrective risk-based platform that can evolve as required.

8.5.3 PERFORMANCE

The normalised profile of unplanned events for the period from RY13 to RY22 is shown in Figure 8-2 below. The unplanned events profile includes asset failures that occur from either inherent or environmental causes. Corrective maintenance work has a direct influence on reducing our inherent network events.

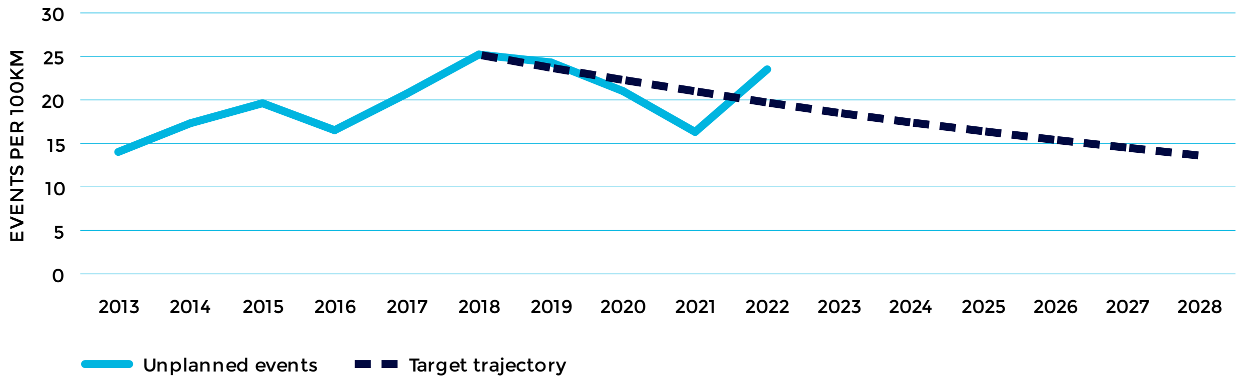


FIGURE 8.2: UNPLANNED EVENTS PER 100KM

There has been a change in trajectory of unplanned events in the RY22 period with an increase in unplanned events, influenced by both environmental and inherent causes, largely negating the gains made in the last two years. Inherent events have increased from RY21, but they are still lower than the average of the previous three years. Environmental events however are significantly higher than RY21 and the average of the previous three years.

To ensure that we continue to progress towards our target trajectory, our corrective investment profile has been adjusted to enable an increase in focus on the inherent events that are included in the overall unplanned event profile. This will aim to ensure that Vector can continue to make progress to align with the target trajectory.

8.5.4 CORRECTIVE MAINTENANCE OBJECTIVES

We have identified the following objectives to guide our Corrective Maintenance programme:

ASSET MANAGEMENT OBJECTIVE	CORRECTIVE MAINTENANCE PORTFOLIO OBJECTIVE
Safety, Environment and Network Security	Ensuring that the network can continue to operate effectively without detriment to the environment or the safety of our people and customers. Our work is prioritised accordingly.
Customers and Stakeholders	Improve the overall experience for our customers and community by improving overall network performance and wherever possible, maximizing the utilisation of any planned customer outage to complete work that is required.
Network Performance & Operations	Asset Reliability – Maximizing asset life and reduce the incidence and impact of failures to our customers by prioritizing work accordingly and reducing overall risk. Operational Efficiency – Enable efficient planning, coordination, optimisation, and delivery of all corrective work activity.

TABLE 8-4: CORRECTIVE MAINTENANCE OBJECTIVES

8.5.5 CORRECTIVE MAINTENANCE INITIATIVES

With the implementation of the RBA as part of our SAP PM system implementation, we have a platform that will support our longer-term asset lifecycle information requirements as well as the ability to use this to support better decision making and maintenance optimisation.

INITIATIVE	DESCRIPTION
Line Clearance	A full LiDAR survey was undertaken across the whole of Vectors electricity network to assess conductor clearances to ground, buildings and structures, waterways and railways as specified in NZECP34:2001 – The New Zealand Electrical Code of Practice for Electrical Safe Distances. The intrusions identified as a result of this survey are now processed into SAP and a program of work has been initiated to verify and scope these in the field including their remediation on a risk prioritised basis. This program leverages the RBA capability already developed to optimise assembly of work packs by risk and being able to identify other open high-risk notifications to be addressed at the same time on the same network section. This minimises disruption to our customers and improves overall efficiency. This program of work has both OPEX and CAPEX elements.
RBA Review Project (Risk Engine)	The underlying risk score engine that supports the RBA is being reviewed. The proposed changes will introduce a V2.0 into production in RY24. As part of our drive for continuous improvement, V2.0 captures the learnings from the last two years and refines the calibration of the risk scores calculated so they are more reflective of the actual risk relative to the other notifications in the pool.
Continuous Improvement	Continuous improvement of our overall corrective RBA to improve effectiveness.

TABLE 8-5: CORRECTIVE MAINTENANCE INITIATIVES

8.5.6 CORRECTIVE MAINTENANCE OPEX AND CAPEX FORECAST

With the improvements introduced in RY21 through the new maintenance standards and supporting changes to our systems, our asset condition assessment knowledge base will expand. This condition information is usually recorded in the form of notifications associated with our assets. As a result, the notification pool will grow larger, but will have better integrity and definition. This improved quantum and quality of information will further support our corrective and pro-active asset management risk-based initiatives and improve the efficiency of our delivery.

There has been a change in trajectory of Unplanned Events/100km as well as the underlying trend of inherent events in RY22. As a result, the previously forecast reductions in corrective OPEX and CAPEX has been delayed ensuring we don't compromise our ability to recover. The trend of Unplanned Events/100km is shown in Figure 8-2 above.

In addition, we are also now forecasting an increase in corrective CAPEX and OPEX in RY24 and RY25 to allow focus on the remediation of higher risk line clearance intrusion notifications. Our corrective maintenance OPEX and CAPEX expenditure forecasts are presented in Figure 8-3 and Figure 8-4. respectively.

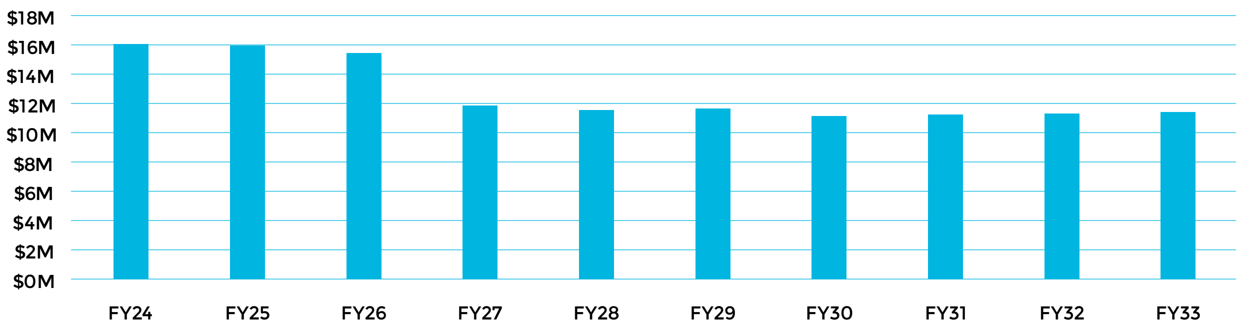


FIGURE 8.3: CORRECTIVE MAINTENANCE OPEX EXPENDITURE FORECAST

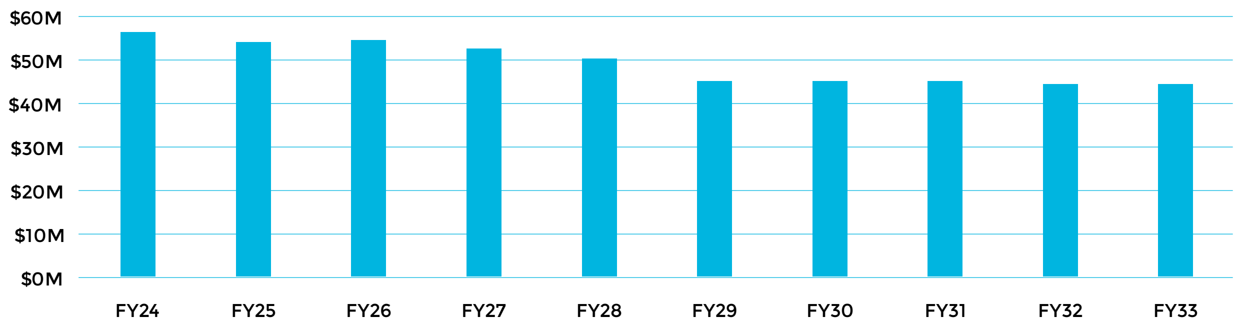


FIGURE 8.4: CORRECTIVE MAINTENANCE CAPEX EXPENDITURE FORECAST

8.6 Routine and corrective maintenance and inspections

Vector's forecast expenditure for Routine and Corrective Maintenance and Inspections is set out in Forecast Operational Expenditure (Schedule 11b) in Appendix 7 as part of the disclosure Report on Forecast Operational Expenditure. A typical breakdown of Vector's expenditure on Routine and Corrective Maintenance and Inspections across the primary asset categories is shown in Table 8-6, reflected as a percentage of the value forecast in Schedule 11b.

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS	FY23 – FY32
Sub transmission Switchgear	5%
Power Transformers	6%
Underground Cables	6%
Overhead Lines	19%
Distribution Equipment	27%
Auxiliary Systems	18%

ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS	FY23 – FY32
Infrastructure & Facilities	14%
Protection and Control	5%

TABLE 8-6: ROUTINE AND CORRECTIVE MAINTENANCE AND INSPECTIONS – FORECAST EXPENDITURE BY ASSET CLASS

8.7 Reactive maintenance

8.7.1 OVERVIEW

Reactive maintenance relates to activities associated with our response to faults and other unplanned network events. These can be broken down into the following activities:

- **First Response** – This is our rapid faults response to unplanned network events. The primary functions here are to make the network safe, initiate and co-ordinate any switching to isolate the fault, restore supply where possible, and to confirm the nature of any remedial work required.
- **Fault Restoration and Repair** – This activity primarily focuses on the restoration of supply to all affected customers. These include the installation of generation, temporary repairs, and the restoration of the network to a fully operational state.

Reactive maintenance addressees all types of faults on the network including faults inherent to the degradation of the asset and faults due to environmental factors. Vector's pro-active and risk-based asset management practices are supporting an improving trend of reduced inherent faults. Faults due to environmental factors (vegetation, weather events, animals, third party damage etc.) continue to dominate unplanned outages. To mitigate the impact of these to our customers, a range of initiatives have been implemented through our Strategic Reliability Management Plan (SRMP) response. Those specifically associated with reactive activities include significant changes to the scheduling and resourcing of response crews, their locations as well their ability to access materials.

8.7.2 REACTIVE MAINTENANCE OBJECTIVES

ASSET MANAGEMENT OBJECTIVE	REACTIVE MAINTENANCE PORTFOLIO OBJECTIVE
Safety, Environment and Network Security	Ensuring that the network can continue to operate effectively without detriment to the environment or the safety of our people and customers. Our work is prioritised accordingly.
Customers and Stakeholders	Minimise impact to our customers and optimise restoration through faster response times, fault isolation and partial feeder restoration, and repairs.
Network Performance & Operations	Asset Reliability - Manage restorations without compromising asset reliability. Operational Efficiency - Continue to seek improvements to our response, isolation of faults to smaller localised areas and reduce impact to our customers.

TABLE 8-7: REACTIVE MAINTENANCE OBJECTIVES

8.7.3 REACTIVE MAINTENANCE INITIATIVES

Planned and corrective maintenance strategies are aimed at improving supply reliability, resulting in fewer faults on the network. When a fault does occur, the reactive maintenance initiatives target two key areas:

- Reducing the number of customers who lose supply when a fault occurs.
- Reducing the duration of the outage for customers who do experience a loss of supply.

INITIATIVE	DESCRIPTION
Optimisation of service provider's fault response model	Vector continues to review and improve on changes introduced to the reactive maintenance model to incorporate 24/7 manned fault response zones, and the approval of additional depot locations across the network. This is aimed at optimising travel times across Auckland to allow our field services teams to respond to faults as quickly as possible.

TABLE 8-8: REACTIVE MAINTENANCE INITIATIVES

8.7.4 REACTIVE MAINTENANCE OPEX AND CAPEX FORECAST

Our reactive maintenance OPEX and CAPEX expenditure forecasts are presented in Figure 8-5 and Figure 8-6 respectively. Our reactive spend increased in RY21 to support our network performance and reliability focus. Our reactive maintenance expenditure forecast maintains this level of focused investment.

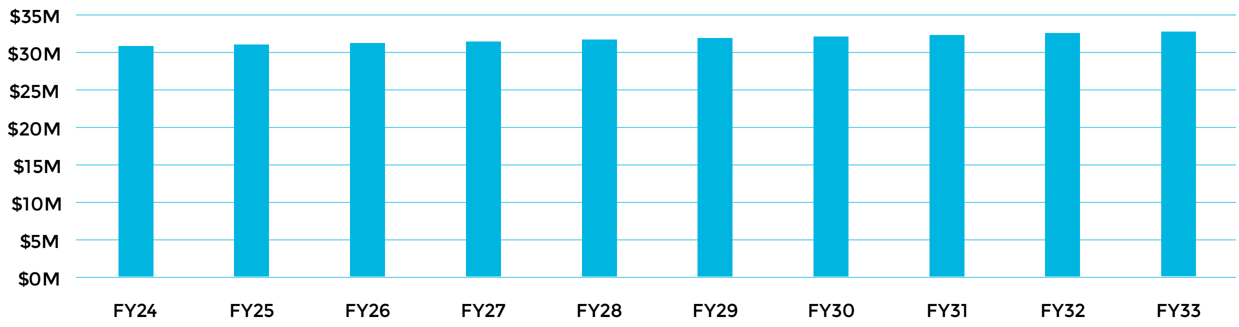


FIGURE 8.5: REACTIVE MAINTENANCE OPEX EXPENDITURE FORECAST

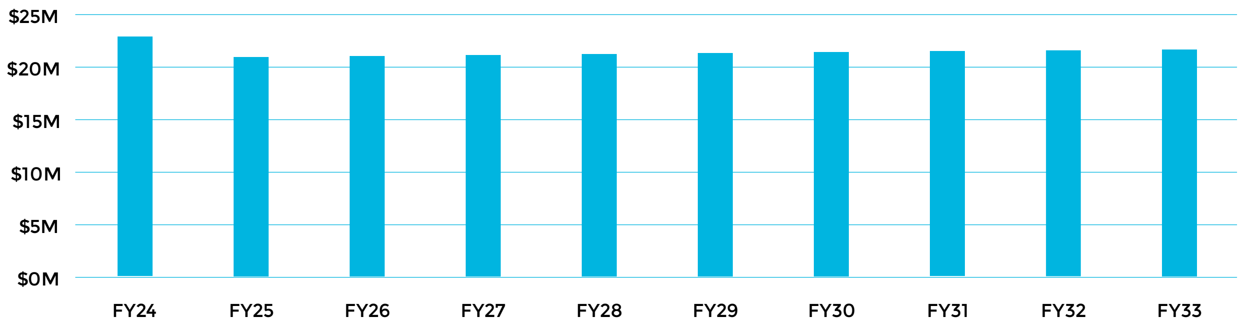


FIGURE 8.6: REACTIVE MAINTENANCE CAPEX EXPENDITURE FORECAST

8.8 Vegetation management

8.8.1 OVERVIEW

Control of vegetation in the vicinity of network assets is an essential activity for a distribution network to ensure we can continue to deliver a safe and reliable service. Management of vegetation is a complex issue, primarily due to the challenges associated with balancing ownership and accountability with amenity and utility value while also ensuring reliability of the network. The Electricity (Hazards from Trees) Regulations of 2003 is the regulatory framework currently in place. These regulations define the obligations of the network and tree owner when defined growth limits are breached. Unfortunately, these regulations have become ineffective and out of date for managing the risk that vegetation pose to the network. An estimated 80% of vegetation related outages are caused by failure modes which are outside the mitigations provided for by current regulation. In addition, the ability to recover costs from the party accountable in the regulations is often impractical.

The elements of Vector's vegetation management program are:

- **Regular inspections and assessment** – Routine inspections of the network are used to identify and record vegetation encroachment as well as for updating our database cataloguing high risk trees.
- **Administration and Prioritisation of work packs** – This activity consolidates vegetation work into logical work pack prioritised by risk as well as the administration of the necessary notifications specified in the regulations.
- **Delivery of vegetation works** – Activities focused on the delivery of the vegetation management works.

Vector has separated the accountabilities associated with these programs. The inspection and administration component is undertaken by a specialist contractor (Arborlab). The physical vegetation management is undertaken by vegetation service providers (Treescape and Asplundh).

Vector has reached agreement with Auckland City Council, for them to take responsibility for addressing council owned vegetation encroaching on the electricity network.

8.8.2 VEGETATION MANAGEMENT PERFORMANCE

Our investment in vegetation aims to mitigate risk on the network. However, the overall effectiveness of vegetation investments is directly influenced by the Tree Regulations. As a result, Vector has taken a strong role within both the ENA and publicly to reform the Tree Regulations to ensure there is greater opportunity for compliance cutting to be designed to deliver both safety and reliability benefits.

Vector continues to advocate for the adoption of a Quantitative Tree Risk Assessment (QTRA) approach. This approach assesses the likelihood of failure of any tree irrespective of its proximity to powerlines, while assessing the consequence of failure using a risk-based criticality model. The risk-based approach seeks to provide a solution by way of a practical framework which determines the risk of vegetation coming into contact with electricity assets and proportionate mitigations - accounting for wider stakeholder and community interests, tree health, and options to respond to risk.

Vector's vegetation asset management strategy (VAMS) forms an integral part of its strategic reliability management plan (SRMP). The framework is designed to be adaptable to new arboriculture and operational data, as well as the different needs of communities and regions, whilst providing a robust and consistent process. By being targeted and preventive, it seeks to avoid both unnecessary vegetation management and outages – supporting affordability and resilience.

8.8.3 VEGETATION MANAGEMENT OBJECTIVES

Vector's vegetation management strategy reflects our strategic asset management objectives. Vector's overhead network exposure to vegetation comprises approximately 8,236 km of total route length. Vegetation in the proximity of these powerlines has a major influence on network performance, especially during storms and high winds.

ASSET MANAGEMENT OBJECTIVE	VEGETATION MANAGEMENT PORTFOL.IO OBJECTIVE
Safety, Environment and Network Security	Ensuring that the network can continue to operate effectively without detriment to the environment or the safety of our people and customers. Our work is prioritised accordingly. This includes the mitigation of fire risk associated with vegetation in the proximity of live electricity assets.
Customers and Stakeholders	Improve the overall experience for our customers and community by improving overall network performance and wherever possible, maximizing the utilisation of any planned customer outage to complete work that is required.
Asset Reliability	Asset Reliability - Maximizing asset life and reduce the impact to our customers by prioritizing work accordingly and reducing overall risk. Operational Efficiency - Enable efficient planning, coordination, optimisation and delivery of all vegetation work activity.

TABLE 8-9: VEGETATION MANAGEMENT OBJECTIVES

8.8.4 VEGETATION MANAGEMENT INITIATIVES

The key initiatives being delivered under Vector's vegetation management strategy are:

INITIATIVE	DESCRIPTION
Continuous Improvement	Continuous improvement and refinement of our vegetation risk-based prioritization methodology. Investigate the use of temporary conductor covers to reduce tree contact in circumstances where negotiations with tree owners are ongoing. When creating new network assets consider deploying technology that provides improved risk mitigation (e.g. fully insulated conductors) based on whole-of-life cost assessment
New Technology	Assessing and developing Artificial Intelligence (AI) capability to predict vegetation growth rates, taking into account the species and climatic conditions at each specific location to be able to better forecast and risk assess potential vegetation intrusions. Utilising soil moisture monitoring devices to better predict when we will have vegetation at risk of uprooting in high winds to improve our levels of preparedness in adverse weather events.
Improved engagement with tree owners	Pro-actively notify responsible parties/owners of vegetation that is not Vector's responsibility to clear, of their obligations to clear vegetation in accordance with relevant standards, so they are aware of a potential breach in advance of it becoming an issue. This would provide the third party with more time to address the issue. Collaborating with large private tree owners, e.g. Auckland City Council, to coordinate vegetation management efforts.
Operational performance monitoring	Implement an external audit program to provide inspection and clearance works quality assurance and influence appropriate contractor behaviour/performance.

TABLE 8-10: VEGETATION MANAGEMENT INITIATIVES

8.8.5 VEGETATION MANAGEMENT OPEX FORECAST

Our Vegetation Management expenditure forecast is presented in Figure 8-7. The forecast incorporates changes to our vegetation management activities including the introduction of increased arborist capacity, independent scoping and auditing, and the collaborative partnership with Auckland City Council, taking responsibility for addressing Council owned vegetation encroaching on the electricity network. There is an increased focus on network hardening and resilience in DPP4.

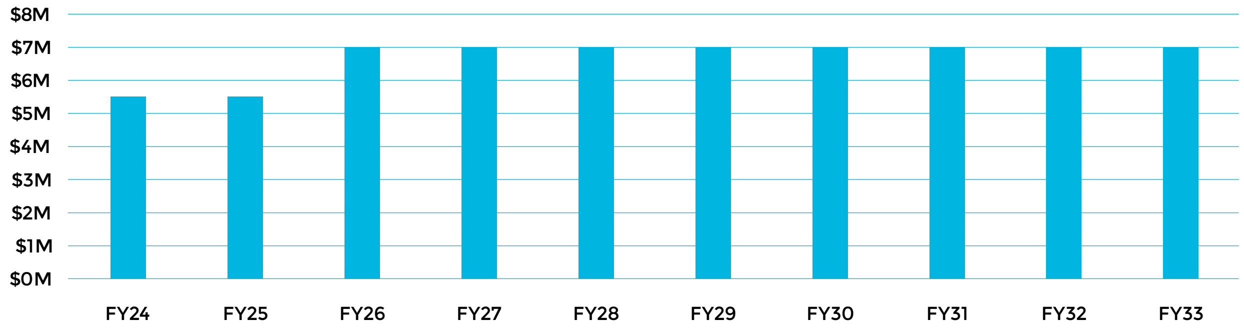


FIGURE 8.7: VEGETATION OPEX EXPENDITURE FORECAST

SECTION 09

Customer connections

9 – Customer connections

9.1 Section overview

This Section explains our approach to connecting new customers, changing customer's connections, managing customer cost and communication, and how we forecast expenditure for these connections.

9.2 Customer connection growth

Reflecting Auckland's continued growth, electricity connections on our network surpassed 600,000 connections in 2022. These additional connections include a range of connections; from small connections such as for residential properties and special vehicle lane cameras to large connections for commercial buildings and industrial properties.

At Vector we utilise our pipeline data in conjunction with modelling (detailed in Section 10 Network Growth) to forecast connection growth. We also work closely with our customers to understand their planned development activities and intended timeframes for these.

9.2.1 LABOUR SHORTAGES AND SUPPLY CHAIN IMPACTS

The impact of COVID-19 impacted more significantly in 2022 than other years with a considerable increase in Illness absences reducing team and crew numbers as well as supply chain uncertainty due to different COVID 19 policies internationally. The war in the Ukraine, limits on migration resulting in skills shortages and growing inflation have also impacted on supply chains and, in some cases, the cost of customer connections.

We are seeing that small developers are most likely to be disproportionally adversely financially impacted. On the other hand, at this time the government is continuing to invest in infrastructure projects as well as social housing and Kiwi-Build.

9.3 Providing cost effective customer network connections

We connect new customers to the network as required through our customer connection process. To ensure an efficient and cost-effective service, small or simple connections are provided by our FSP for that part of the network at a unit rate. For larger or more complex connections, customers can elect for a price from both FSPs to ensure a competitive pricing process.

Vector provides full information on our website in relation to:

- our process for providing new connections or changing existing connections.
- our policy on customer capital contributions to new connections or changes to existing connections.
- our approach to planning and managing communication with consumers about new or altered connections; and
- the factors that may impact on the potential timeframes for different connection types.

9.3.1 DESIGN AND BUILD PROCESS

Customers can initiate a connection request through several different channels, including our web self-service portal, contact centre or by contacting our customer contracts team or their key account manager directly. Depending on the complexity of the proposed connection(s) the connection request will be managed by either our Connections Team (small / simple connections), Customer Projects Team (large connections) or our Major Projects Team (large complex connections or infrastructure relocations).

The Vector network is divided into two areas, each of which has a Field Service Provider (FSP) that are responsible for designing, building and maintaining the network in their area (zone). Small or simple connections are priced using agreed unit rates and the connection will always be built by the zone FSP. This is to enable a quicker turnaround from request to completion of the connection. For large and complex projects customers have the option for their connection to be priced by both FSPs, ensuring a competitive pricing process. Our Customer Contract Advisors work closely with customers to ensure that their requirements are understood, to provide further information such as possible consent requirements or impact of legislation related to building near existing electrical infrastructure as well as to ensure that an optimal design and quote is developed. The Customer Delivery Advisors work closely with our customers and the Service Provider project managers during the build phase of the connection assuring that the installation is as per the agreement.

Vector's engineering teams have developed robust design standards to ensure that a safe and resilient network is built in accordance with legislative requirements, and which meets our Asset Management Objectives. All customer connections are designed to comply with these standards ensuring the integrity of our network and quality of supply to existing and new customers. Our Planning Engineers review all material changes to the network ensuring that the network is reinforced at the right times to cope with new connections being added.

9.3.2 COST OF CONNECTION AND DEVELOPMENT CONTRIBUTION

From 1 December 2021 Vector changed the way it recovers the costs of overall electricity network growth, so that those who are driving the need for investment in network growth will now cover the costs of doing so. When a new connection is added to the Vector's electricity network or the capacity on an existing connection is increased, the entity requesting the connection or change in capacity pays the full cost of the connection at the point of supply, plus a contribution towards the future costs of supplying electricity to the connection as overall demand increases over time.

This new approach provides greater equity and affordability across all customers on the network, ensures Vector's pricing is more cost-reflective, and is consistent with other infrastructure providers in the region.

Part of these changes included Vector expanded its standard electricity connection cost for new connections to connections that comply with the following criteria:

- It is a new connection
- There are five or less connections (including the proposed new one) at the same development
- It fits into one of the following categories:
  - Residential single phase / 60 amps
  - Residential two phase / 60 amps
  - Residential three phase / 60 amps
  - Commercial single phase / 60 amps
- It does not require a Vector easement or change to a transformer.

All other electricity connections are considered non-standard and a price will be quoted on the design and build assessment.

In some circumstances the connection applicant may undertake some of the work that would otherwise be covered by the capital contribution. Vector may allow consumers or the connection applicant to undertake the preparatory work using appropriately trained persons and with all work to be completed to Vector's standards and requirements prior to Vector installing the new electricity infrastructure. Preparatory work includes by way of example, trenching and or civil work, reinstatement and laying of duct.

9.3.3 LARGE AND COMPLEX CONNECTIONS

Central and local government as well as large local and international commercial enterprise infrastructure investment decisions directly impact on our capital investment choices. We have recently seen exponential growth in data centres being built in Auckland and significant investment in commercial EV chargers. Government driven examples include the proposed light rail line (Auckland Light Rail or ALR) from the city to the airport; Kainga Ora's large-scale redevelopment of existing neighbourhoods; major motorway development projects; electrification of buses and ferries and continuing investment related to Watercare, Auckland Transport, Auckland Council, universities and District Health Boards.

Our key account team manage the direct electricity conveyance contracts with several large customers on our network. These customers understand our network performance but also make individual decisions around network resilience and configuration to manage their unique requirements. They also provide dedicated account management for the large roading, rail and water infrastructure projects around Auckland. This ensures these large infrastructure projects have the greatest possible synergies and cause the least possible disruption for the public.

9.3.4 CONNECTION OF CUSTOMER DISTRIBUTED ENERGY RESOURCES (DER)

One of our Asset Management Objectives is to prepare the network for future changes that will include amongst others, the connection of customer DERs. When a customer wants to connect a DER to Vector's network the application is done via Vector's website. The website provides clear guidelines and standards that ensures that the network has sufficient capacity and capability to provide the required service levels and allow for the orderly and safe connection of distributed generation for a new application.

Vector needs to know where all distributed generation is connected and located to ensure that the equipment meets safety and operational standards as well as to ensure compliance with Part 6 of the Electricity Industry Participation Code (2010).

There are two options in Vector's website for distributed generation: less than 10kW or more than 10kW: the first step is for a customer to check whether there is congestion in the network (for DERs rated less than 10kW, congestion is usually not an issue but if it is Vector will inform the customer accordingly). Furthermore, customers need to ensure, as part of the application, that the inverter that they plan to use has been pre-approved for use in Vector's network; the Vector website provides a list of pre-approved inverters with full details.

The application form to install a DER and connect it to Vector's network is available on the website and Vector commits to acknowledge an application within five days and will review and approve (or decline if there is a reason), an application within thirty days. The last step in this process, after a DER installation has been approved, installed and tested, is for the customer to provide a signed certificate of compliance that outlines the scope of the installation and as well as confirm compliance with the AS/NZS standards for inverters and wiring installations.

The process for DERs greater than 10kW is very similar to those for less than 10kW but there is a chance in some parts of the network, that congestion could preclude the connection of a DER – especially where the proposed DER will contribute significantly to fault levels.

Customers now have a number of options available to them for improving resilience, thanks to existing and new technologies, whose costs are steadily reducing. These include:

- Mobile on-site generation
- Permanent on-site generation

- Renewable generation with on-site energy storage
- Battery energy storage
- Solar and battery storage solutions
- Innovative V2H solutions that use the energy stored in an electric vehicle, so customers can supply their home with energy during an unplanned outage.

9.4 Customer connection forecast expenditure

Customer connection CAPEX is primarily driven by population growth (residential) and growth in commercial/industrial activity. Our forecast expenditure is based on trending historical connection activity using the FY23 forecast as a baseline and incorporating econometric parameters and customer growth insights. Step changes due to connection requests from major customers are included in our 10-year forecast.

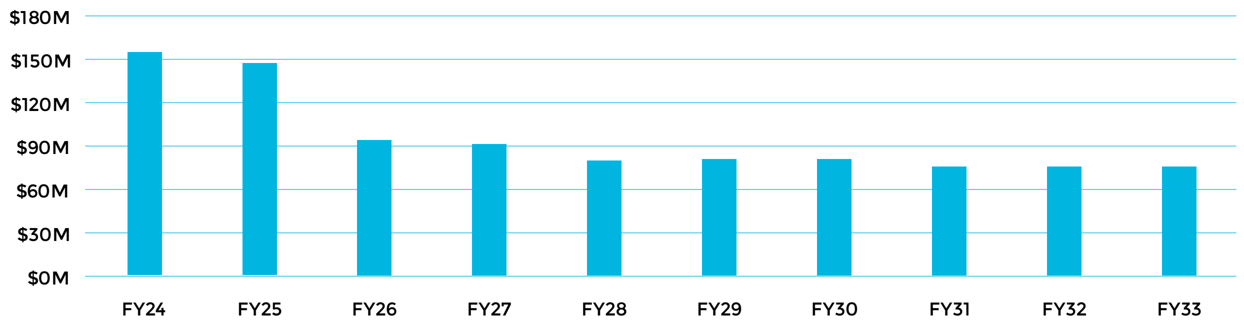


FIGURE 9.1: CUSTOMER CONNECTION EXPENDITURE FORECAST (GROSS)

SECTION 10

System growth and security

10 – Network growth and security

10.1 Overview

This section describes the processes and systems Vector has implemented to identify where investment is required on the network to resolve network constraints, meet changes in electricity demand, manage changes in customer consumption behaviour, improve climate resilience and create the future energy network.

Network planning is about providing a reliable and resilient network in the long-term interest of our customers by developing a cost-effective electricity supply to meet new and future demands (e.g. organic growth, new development, urbanisation) and changing customer needs (e.g. energy efficiency, electrification of transport). This requires balancing supply side options with demand side solutions to ensure a network that is more flexible and responsive to changing customer behaviour and the increasing rates of renewable technology adoption.

Given electricity infrastructure typically has a life of more than 40 years, even planning for the near-term (next 5 years) must take into account the long-term need for infrastructure, managing uncertainty and avoiding stranded assets. Today, uncertainty is higher than ever due to rapid technology innovation and changing customer preferences which also challenge market and policy prospects. The majority of the factors driving uncertainty are out of Vector's control, which means that network planning needs to be scenario based and increasingly dynamic and flexible to pivot and adjust as the future evolves, while always ensuring timely investment and delivery of network projects.

We also recognise the changing technology landscape and how our customers will use the network may change as a result. In comparison to a few years ago when our largest market segment, the residential market, primarily used electricity for cooking and heating, we are seeing electricity being increasingly used for sewerage management (e.g. pumped schemes are substituting gravity flow systems), working from home and home-based education (e.g. step increase following the COVID-19 pandemic) and transport (e.g. the electrification of transport). This customer transition forms a significant input to our planning, to ensure we only build assets that are needed for the long term and reduce the risk of stranded assets.

To this end, our planning aims to transform our network to enable customers to interact and actively participate through distributed energy resources (i.e. solar PV and batteries) and load control. This will promote a lower-cost, smarter, and more decentralised electricity network which will also improve its resilience. This is in essence Vector's Symphony strategy from a network development perspective.

The following sections describe:

- overview of the asset management objectives and strategies applicable to network growth and security (Sections 10.2 and 10.3)
- our network planning approach and process, including (Section 10.4):
  - the critical steps in the planning process,
  - demand modelling and constraints identification.
  - how different solutions to address the constraint or meet the demand growth are assessed, including non-network options, and
- opportunities for non-wires alternatives (Section 10.5)
- the impact of COVID 19 on network demand (Section 10.6)
- finally, the major investment in security and growth projects to address identified constraints and demand growth are described (Section 10.7).

10.2 Growth and security objectives

10.2.1 ASSET MANAGEMENT OBJECTIVES

The asset management objectives that are addressed through the network growth and security programme of works and investments are set out in the table below.

FOCUS AREA	OBJECTIVES
Safety, Environment and Network Security	• Comply with relevant safety and environmental legislation, regulation, and planning requirements. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and Stakeholders	• Enable customers' future energy and technology choices. • Ensure the long-term interest of our customers by providing an affordable and equitable network.
Network Performance & Operations	• Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with Security of Supply Standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets, and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future Energy Network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc. – operations: transition to distribution system operator model and whole-of-system planning. • Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third-party flexibility traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

TABLE 10-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

Additionally, the following customer-related objectives specific to system growth apply:

- Manage the increasing load forecast uncertainty due to the unpredictability of the timing of large customer projects, changing customer behaviour (e.g. hybrid working arrangements) and the rate of our customers' adoption of new technologies.

10.3 Strategies to achieve the objectives

To meet these objectives, the following strategies are employed.

10.3.1 UNDERSTAND FUTURE TRENDS FOR LONG TERM PLANNING

Our planning process is anchored on granular bottom-up data analysis at customer level [1]. We use a Customer Scenario Model to forecast trends and their impact on our network and gain a clearer understanding or predictions of the future energy demand out to 2050. This modelling forecasts electricity growth based on expected volumes and locations of new customer connections, technology uptake and energy efficiency gains. It uses data from customer usage trends and changes to customer behaviour

[1] Heinen, S., Richards,, P., (2020), Towards customer-centric energy utilities - A granular data-driven bottom-up approach to understanding energy customer trends, The Electricity Journal, Volume 33, Issue 9, 2020.

(from smart meter data), as well as results from industry trials (see case studies on EV Smart Charging Trial and Smart Hot Water Trial), regional and national forecasts, and consumer surveys. To ensure that we adapt and respond to changes, the model is continuously refined and updated. Further details of our scenario modelling areas are set out in section 10.4.

CASE STUDY: EV SMART CHARGING TRIAL

In 2022, Vector completed a multi-year EV smart charging trial with 200 real-world customers. The trial demonstrated that smart charging can seamlessly integrate EV charging demand into the existing network while maintaining customer satisfaction. More resources on the learning of the trial are available on our website.

https://www.vector.co.nz/articles/ev-smart-charging-trial

An immediate benefit of the trial has been that we can accurately estimate the impact of unmanaged EV adoption on the network. This is now used in our scenario model as well as for customer connection requests. After diversity maximum demand (ADMD) describes the peak contribution across a group by considering behavioural differences. It is a well-known and widely used metric for designing electric assets and has historically been established by measuring the aggregate demand across a group.

Granular time series data, such as EV charger data and smart meter data, can compute ADMD as a function of group size to determine an ADMD curve (Figure 10-1). With the increasing number of EV chargers, the ADMD curve exponentially drops. As the number of EVs on a network asset is increased, it becomes statistically less likely that the customer behaviour is aligned and that they charge at the same time. In other words, the behaviour is diverse. At a level of the network with 100 EVs or more (e.g. MV, HV and generation), the curve has flattened out and load is diversified. A group of 100 EV chargers has an ADMD of 1kW per EV so would require 100kW of network capacity. When the number of EVs is low, for example an LV network with 10 EVs (which is common in a rural network), the ADMD is about 3kW per EV. To accommodate 10 EV chargers, an electricity network of 30kW capacity is required. In other words, by lowering the number of chargers to 10 in the last example, the network capacity required is only reduced by a factor of 3. Clearly, EV charging will affect the LV network proportionally more. An emerging issue is that the LV network has traditionally built to 'fit and forget', with changes being driven by asset failure or customer complaints. To meet today's customer expectations, this is no longer an appropriate situation and that the industry will require increased visibility at the LV level to monitor and deliver to the future needs of electricity customers.

Ongoing customer engagement and data is required to stay abreast of the ADMD development as EV adoption matures and deliver cost-efficient and reliable EV integration.

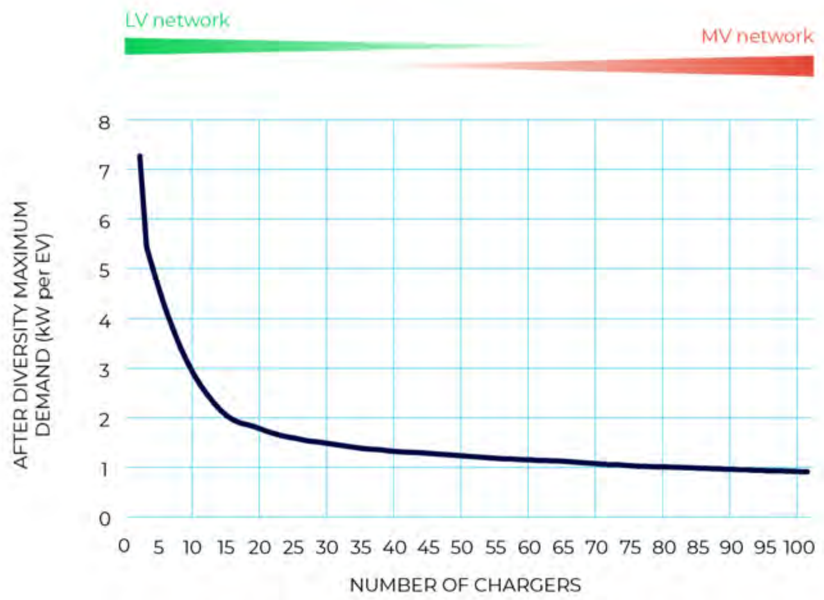


FIGURE 10.1: ADMD CURVE FOR EV CHARGING

10.3.2 ENGAGE WITH CUSTOMERS & STAKEHOLDERS

In an uncertain environment, customer and stakeholder engagement is pivotal. We have dedicated teams that engage with small and small to medium commercial customers, developers of large residential and commercial projects, large commercial customers, and Auckland infrastructure providers (e.g. road, rail, telcos, water). Those engagements identify synergies for system growth projects and customer projects, therefore minimising direct and indirect costs, such as disruption of traffic and local businesses. Those engagements also mean that our network developments plans are informed by latest developments of large-scale customers as well as new connections. (incl. distributed generation and storage). Our open data portal and the two new interactive maps (see case study below on interactive maps) also facilitate very early-stage engagement with customers and stakeholders but do no replace a formal connection process.

We develop large-scale connections and connections in close collaboration with the customer and their consultant, and continuously ensure alignment to the system growth projects. Customers submit details like their demand/injection levels, presence of special appliances (such as industrial motors) and required redundancy based on which Vector is developing options. At this stage, synergies with system growth projects are also considered. If the customer commits formally, then the new or expanded customer connection will also be reflected in the load forecast and network constraint modelling (See Section 10. 4). To manage network risks for all connected customers, all customer projects need to comply with key standards and regulations (see next section). Preliminary connection requests are not reflected in the asset management plan process (e.g. load forecast and network constraint modelling). However, not all committed customer projects go ahead as initially planned, given that our customers operate in a dynamic market where plans change. Continuous customer engagement means latest customer information (demand/injection, connection date) is received, and, given that the physical delivery (engineering design, construction, and commissioning) of our system growth projects is typically less than 2-3 years, there is opportunity to refine the plans.

The recent boom of data centre connection applications has demonstrated that our process is robust and flexible to adapt to unexpected requests. Over the last two years, several large tech and data centre providers have announced to build data centres in Auckland due to the exponential rise in cloud-based services, demand to store data in New Zealand for governance reasons and excellent connectivity of Auckland to global fibre backbone. Early and continuous customer engagement means that Auckland now already has 20 MW of new data centres connected and much larger connection pipeline.

CASE STUDY: INTERACTIVE MAPS FOR NETWORK HEADROOM AND SYSTEM GROWTH PROJECTS

To support customer and stakeholder engagement, Vector publishes key network information on its open data portal (https://data.vector.co.nz/) where users can not only visualise detailed geospatial information of the network but also conveniently download the raw information for use in their own systems or more detailed analysis in expert tools. The information available includes location of assets (ZSS and 11 kV feeders), the boundary of our coverage area and ongoing and future works for network projects (within next 2 years)

Based on customer and stakeholder feedback, the open data portal now also hosts two new interactive maps for network headroom and all system growth projects covered by this 10-year AMP. The network headroom map indicates the headroom in the 11 kV network for winter and summer peak conditions. The expectation is that this map supports early-stage customer engagement. For system growth projects, the AMP always provides a comprehensive view of expected expenditure, timing and options considered (Section 10.7 and Section 10a). The new interactive map will complement this information by providing a spatial visualisation, which ensures the stakeholders and customers can easily identify the projects planned in their area of interest.

10.3.3 COMPLY WITH SECURITY OF SUPPLY, POWER QUALITY AND OTHER REGULATIONS

Vector will comply with the relevant regulatory obligations and industry standards. The most relevant to growth and security are compliance with the Security of supply Standards (SoSS) (ESP010) which contribute to achieving the DPP3 Quality Standards and Power Quality requirements.

Our SoSS (summarised in Section 7) sets the probabilistic planning criteria for network development. This defines the number of coincident outages that can occur without loss of supply to customers and the time allowed to restore supply after an asset failure. If our network can by design not deliver this requirement, then a system growth project is triggered. The SoSS will provide customers with an acceptable reliability of supply at an acceptable cost. This involves understanding where there may be short- or long-term network constraints and planning for them.

We use our load forecast model, which combines organic growth from the scenario model with point loads (e.g. residential developments, data centres), to identify load requirements across the different network voltage levels (e.g. GXP, sub-transmission, zone substation (ZSS) and feeder) over the next 30 years. These load requirements combined with asset rating information and the SoSS, is then used to identify network constraints and capacity shortfalls using network modelling tools (e.g. load flow modelling). Reinforcement options and eventually network and non-wires projects are then designed to mitigate the SoSS breach. The capacity of new assets required to be installed are determined based on the size of constraints identified, the forecast demand growth and specifications of standard assets used by Vector.

Power quality is achieved through ensuring appropriate voltage levels and harmonics are maintained within prescribed limits. Where power quality issues are identified, Vector investigates the cause and follows the planning process to develop the most appropriate solution (See Section 7).

10.3.4 CONSIDER DIVERSE TOOLBOX OF SOLUTIONS FOR NETWORK PLANNING

To invest efficiently we use new technologies and understand future trends and customer behaviour, so we invest in a much smarter way. Our aim is to run the existing network smarter, and only invest in new infrastructure when we absolutely have to. The traditional approach to meet increased network demands and our SoSS has been to increase the capacity of existing assets or add new assets such as zone substations and distribution feeder circuits. With the change in customers behaviours' and needs, the current and future advancement of technologies and the attention to carbon emissions, our toolbox of solutions for network planning has become much more diverse. Our new approach promotes a lower cost, smarter, more decentralised but more connected network, rather than potentially overcapitalizing in projects that could result in or creating stranded assets. (see case studies on EV Smart Charging Trial and Smart Hot Water Trial)

When planning for network development, we consider:

- The long-term (life cycle) costs of investments in the long-term interest of consumers;
- The use of probability-based incremental planning methods;
- Risk-based scenario models
- Continuous engagement with large-scale customers to ensure demand and timing-of connections is kept updated

- The agility and flexibility of solutions to be able to adapt to emerging technologies and urban development trends;
- The use of non-network solutions such as digital platforms to enable distributed energy resource integration;
- Use of data analytics and advanced operational practices;
- Non-network solutions such as demand side management strategies (including engagement with customers and third-party service providers) to reduce peak, and
- Network reconfiguration to improve the utilisation of existing assets and reduce losses.

These considerations are made via our capital expenditure justification process that is described in Section 10.5 and Section 10.6.

10.3.5 GROW DEMAND MANAGEMENT VIA OUR DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)

We are actively enabling the transition to a clean, reliable, and affordable energy system through our use of our distributed energy resources management system (DERMS). DERMS is a platform that controls and manages the ever-growing number of third-party owned Distributed Energy Resources (DERs [1]) connected to the network. DERMS provides visibility and active demand management so that DERs can maximise their consumer and system value within the available network limits (considering actual operational conditions) (Figure 10-2). This reduces the need for traditional network reinforcement and accelerates the adoption of DERs. We are building capability to on-board customers (typically large commercial energy users – See case study on powering Auckland's E-Bus Fleet) onto Vector's Distributed Energy Resource Management Systems (DERMS) platform. While communication protocols are rapidly evolving, we have published our preferred interoperability mechanisms in the DERMS connection standard (ESS900). Engagement with technology providers, customers and third-party service providers have concluded that the key protocols for DER integration today are IEEE 2030.5, OpenADR and OSCP. While the protocols will continue to evolve and we will need to remain flexible, we can provide based on today's perspective clear direction to customers and third-party service providers one how we can communicate real-time network information to them. Together, our demand management systems and DERMS enable reduction of peak demand that needs to be supplied through our network, therefore allowing us to defer investment, maintain reliability and minimise costs to our customers.

Section 2 provides further details on the targets of orchestration in our future network roadmap and how we have revised our network connection standard and published a new metering guideline to ensure a consistent system architecture and interoperability across network, DERs and third-party service providers.

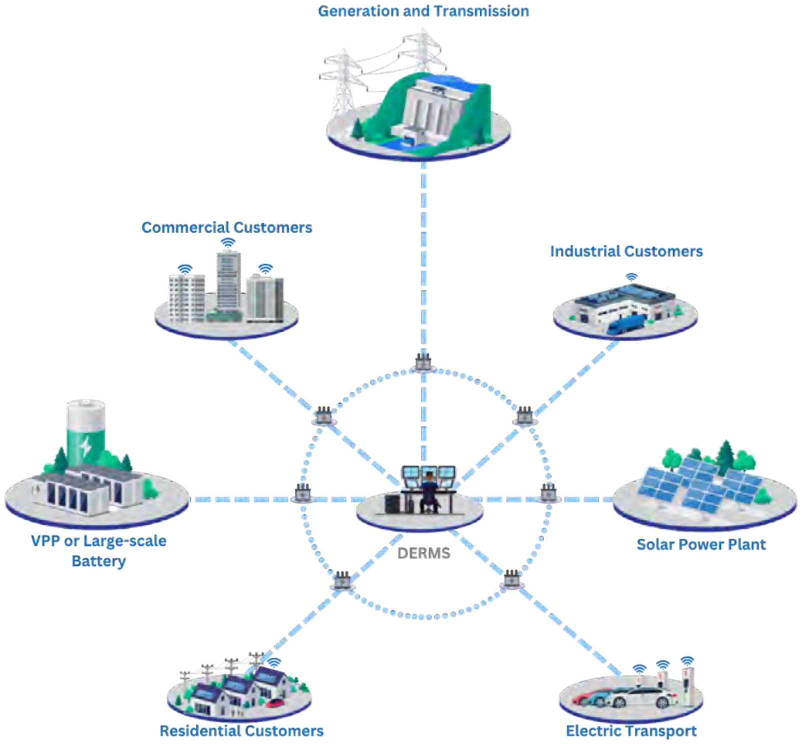


FIGURE 10.2: CUSTOMER AND NETWORK INTEGRATION VIA DERMS FOR COST-EFFICIENT AND RELIABLE DECARBONISATION

[1] Distributed energy resources is an umbrella term which includes connected devices such as distributed solar panels, batteries, heat pumps, pool pumps, electric vehicles as well as more aggregated load types such as smart buildings, large-scale batteries, data centres or e-Transport fleet depots.

CASE STUDY: VECTOR AND AUCKLAND TRANSPORT POWERING UP AUCKLAND'S E-BUS FLEET

We've joined forces with Auckland Transport (AT) to help electrify Auckland's bus fleet. That's no mean feat with 1,400 buses to be converted to zero emissions vehicles by 2030. The work began in 2020 when Vector and AT signed a Memorandum of Understanding to look for opportunities to reduce the costs of bus charging infrastructure, so that the transition can be more affordable. Last year we completed a detailed study into what it would take to electrify the whole fleet, with high-capacity charging infrastructure at each of AT's 21 bus depots across the city, which is now reflected in this AMP.

The latest milestone will see the electrification work begin, with three bus depots set to be electrified by the end of this year. The head of metro services at AT, said this project would help reduce carbon emissions and improve air quality in the city. The newly electrified bus depots will have capacity to charge 20 to 30 buses each. This will mostly happen overnight, and the charging will be 'fleet managed' to achieve as smooth a load profile as possible.

Both these factors will reduce the impact on the electricity network, leading to cost efficiencies for Vector and Auckland Transport, which then benefit both organisations' customers. The fleet managed charging is coordinated through Vector's Distributed Energy Resource Management System (DERMS), which provides the transparency and simplicity required to make this work. The first DERMS-connected depot went live in January 2023. This collaborative project is a stellar example of Vector's Symphony strategy, finding innovative ways to deliver positive benefits for the customer, the business, and the environment.

10.4 Network planning process

Vector has developed an integrated Symphony planning approach to meet our SoSS, QoS, and PQ requirements. Symphony planning starts with developing a model that describes the demands placed on the network from a customer-level and builds our understanding of future network requirements from the bottom-up. The advantage of this approach is that locational differences are reflected and can inform options analysis. Also, new customer behaviour and technology adoption can be observed and considered in its early stages, allowing for more foresight and preparedness in the planning process, as well as more active customer engagement. Finally, our options analysis considers not only wire solutions (e.g. cables, lines, transformers) which continue to serve us well, but also innovative non-wires solutions (e.g. smart hot water control, batteries, smart EV charging that is often owned by customers or third-party providers), in line with our strategy to only build new infrastructure when there are not more affordable solutions available. In the context of heightened uncertainty over future planning scenarios, non-wires solutions offer additional benefits: they are less intrusive in road corridors and heavy engineering works are reduced (i.e. a smaller community impact and more agile to deploy); and they are also more modular (i.e. can start at a small scale and grow incrementally) reducing the risk of stranded assets by dynamically matching needs as they evolve over time.

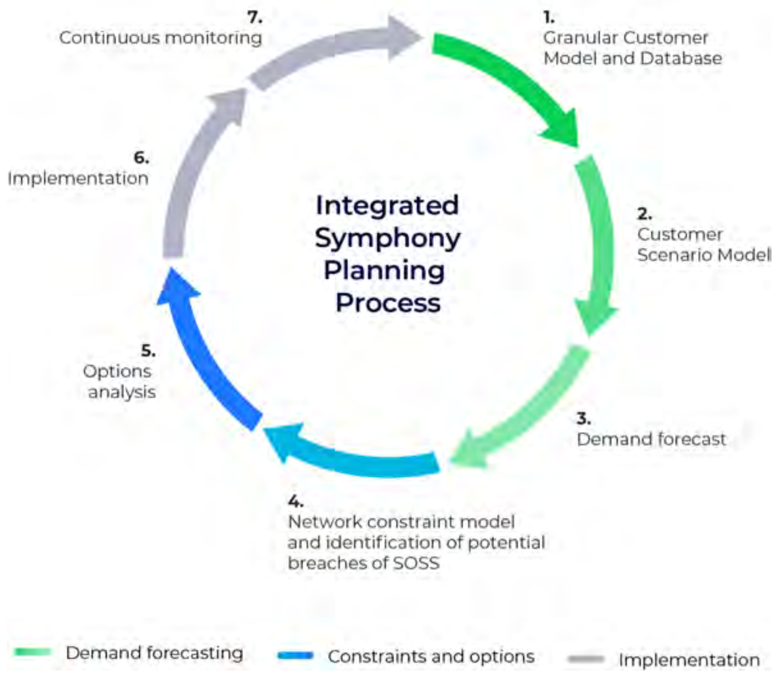


FIGURE 10.3: STEPS IN INTEGRATED SYMPHONY PLANNING PROCESS

The planning process is initiated by an annual assessment of the customer peak loading on all distribution feeders and zone substations. This reassesses the summer and winter loading and security levels. The distribution network loading and security assessment includes thermal limits and voltage modelling.

The capital expenditure justification process, described in section 10.5, ensures appropriate governance and rigor is applied to network development and investment decisions made through this network planning process.

10.4.1 DEMAND FORECASTING

The first three steps of the network planning (Figure 10-3) process are related to demand forecasting based on a detailed bottom-up build that takes into account historical demand, customer demographics and emerging trends.

The **Granular Customer Model and Database (Step 1)** is the basis of the bottom-up modelling process and brings together all information of Vector's customer today. The granular customer model and database combines all of Vector customer and energy information and links it to a wider set of information such as building characteristics and socioeconomics. The resulting model operates at ICP level and provides a granular view on changing energy consumption patterns, customer profiling and new technology adoption [1].

The **Customer Scenario Model (Step 2)** draws from the detailed Customer Model and additional demographic data to model future changes in incremental electricity demand and consumption. The model considers future changes due to population growth, employment growth, energy efficiency, as well as electrification- and decarbonisation-driven trends like distributed solar PV and battery energy storage systems, electric vehicles, water heating load and gas-to-electricity conversion. Learnings and data from various Vector trials (see case studies on EV Smart Charging Trial [2] and Smart Hot Water Trial) are fed into the model. Non-wires solutions that can be owned by customers or third-party providers and are managed via DERMS to avoid network reinforcement are also modelled. While the AMP covers a 10-year period, we run all our scenarios over a 30-year horizon to portray longer term impacts and derive short-term actions that prepare us for the future. Figure 104 provides an overview of the model.

The Customer Scenario Model represents our Auckland service territory in 548 geographical areas. Each zone, called Macro Strategic Model zones (MSM), cover roughly 1000 homes and is the size of a small suburb. The definitions of these zones and the socioeconomic inputs are unified across various government departments and service organisations via the Upper North Island Forecasting Network (UNIFN, previously Auckland Forecasting Network) [3].

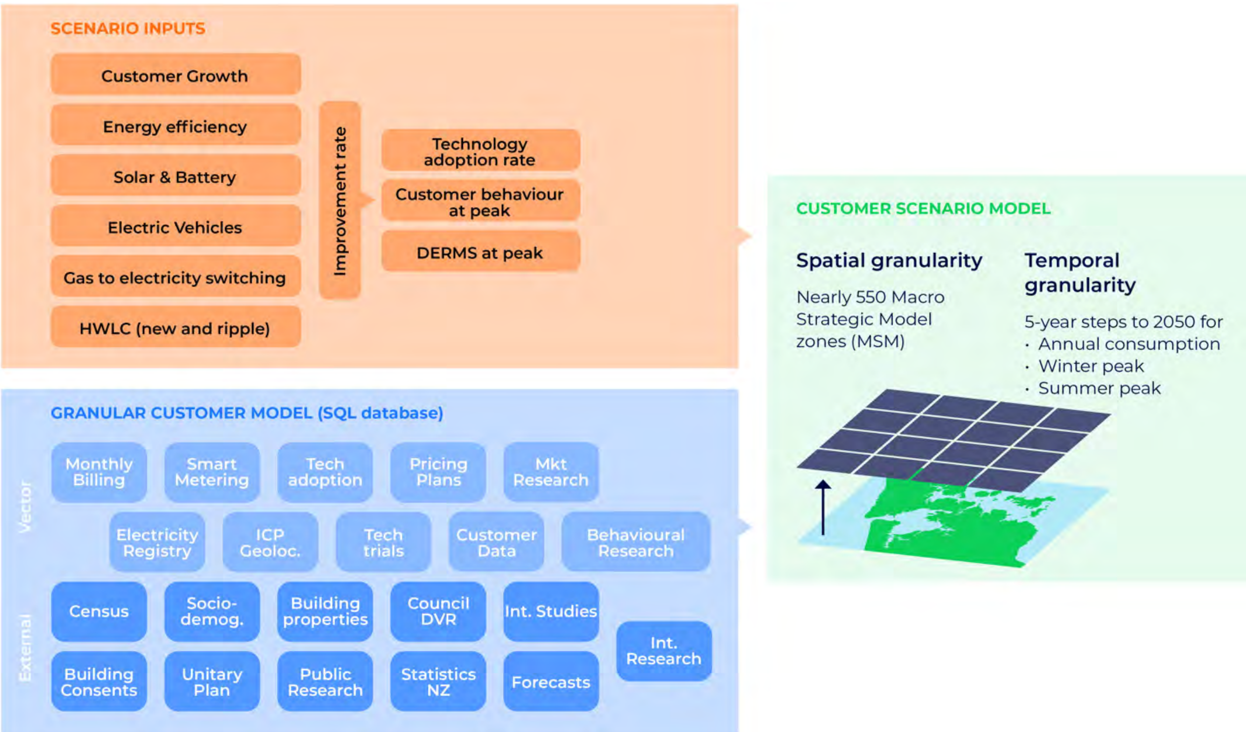


FIGURE 10.4: OVERVIEW OF CUSTOMER SCENARIO MODEL

[1] A detailed paper on this is publicly available at https://www.sciencedirect.com/science/article/abs/pii/S1040619020301287

[2] More information on the EV Smart Charging Trial is available here https://www.vector.co.nz/articles/ev-smart-charging-trial

[3] Upper North Island Forecasting Network (UNIFN) - Previously known as Auckland Forecasting Network, the purpose of the UNIFN is to support the delivery of timely, tailored and effective public infrastructure, social and community services through consistent, integrated, responsive and best practice demand forecasting. The 30+ UNIFN members include organisations that either: (i) Deliver the key public infrastructure, social, employment, visitor and community services in and/or for Auckland, or (ii) Agencies responsible for population, employment, visitor and land use forecasting scenarios and projections

CASE STUDY: SMART HOT WATER TRIAL

Smart hot water is the capability of granularly controlling hot water cylinder demand at the individual cylinder level in order to manage peak demand and distribution network capacity requirements across different topology levels. The capability can also bring benefits upstream to national energy and ancillary service markets. We used our Smart Hot Water pilot system in Te Atatu on about 100 ICPs combined with smart meter consumption data to confirm the load response of about 0.6kW/ICP, which further cemented the viability of smart hot water as a non-network solution. The results also re-confirmed the importance and challenge of bringing 'load back' after using them to avoid peak constraints. After utilising hot water for a peak shaving event, a new secondary demand peak occurred at around 20:00 that exceeded the uncontrolled demand peak, because the natural diversity from hot water cylinders was removed and all of the controlled hot water cylinders began heating synchronously. This highlights the importance that electricity distributors place on orchestrating load restoration so that actual network conditions can be considered. In some circumstances, the secondary peak is not an issue if the residential LV assets are not constrained, and the objective of peak shaving is to mitigate the demand load on an upstream network asset which combines residential and commercial loads. However, if the peak on the residential-only network assets needs to be mitigated, this secondary peak must be managed by restoring load more gradually. If a third-party provider or retailer were to manage hot water load for consumers then the coordination with the network via a DERMS or Load Management Protocol, accounting for real-time conditions and constraints, becomes even more critical.

FIGURE 10.5: LOAD CONTROL RESPONSE DURING 10 HIGHEST PEAK DAYS IN WINTER 2022

Demand forecast (including network allocation) (Step 3) brings together the organic growth from the customer scenario model with non-standard or large customer projects such as known large housing developments, new commercial developments, or factories, and, increasingly, data centres. The present asset peak loading is established based on preceding years and normalization for abnormal network configurations. The incremental growth from the Customer Scenario model, which runs at neighbourhood level, is then allocated to electricity network assets based on network topology. Combined with non-standard and large customer projects, the demand 11 kV forecast for the next 30 years is then derived across different network levels (GXP< zone substation, 11 kV/22 kV feeder) by taking demand diversity into account. Customer-level smart meter data is then used to link the Customer Scenario results to network assets.

CASE STUDY: UNLOCKING SMART METER CONSUMPTION DATA

Creating a dynamic time-series view of the 'whole of network consumption' has been the vision at Vector for more than 5 years. This information is a key input into many aspects of Vector's symphony strategy, and supports the optimisation of planning, operations, customer service and pricing. Gaining access to smart meter data was identified early on as the most efficient method to achieve this goal as an industry. The value of smart meter consumption data can be harnessed without requiring the installation (and investment in) additional devices at additional cost. A cost which could ultimately be borne by our customers.

Over the past years, Vector has contracted with retailers on our network for the supply of half hour consumption data (kWh). This critical milestone took many years to achieve. Our journey to receiving consumption data began with the New Part 10 of the Code, which went live in 2013, including the new retailer-appointed MEP model. Under this model, retailers were initially either reluctant or unable to provide data to EDBs. Some retailer-MEP agreements had restrictive data access terms. In the latter half of the 2010s, there were extensive concerns by retailers around privacy and permitted uses of data if they were to share consumption data with any party, including EDBs.

Code changes in 2016 to open up data flows did not work as intended. We were however able to receive some consumption data for a portion of our customers for a single year. This was instrumental in developing our internal capability and processes. In particular this data supported the development of the scenario model for the network planning process.

In 2020 the publication of the default distributor agreement (DDA) started to open the door but there were still limitations:

1. Rules prohibited data being combined with other datasets, reducing the usefulness of the data for network planning purposes
2. Default delivery frequency was six-monthly
3. The DDA solution did not consider practicalities of MEPs liaising with EDBs for data provision

Today, we have DDA based data agreements in place for 99% of our ICPs under contract, and we are currently receiving consumption data for 84% of ICPs on a monthly basis. We have received historic data back to 2017, giving us a five-year 'whole of network' dataset.

Some of this data is provided direct from the retailer, some via the MEP (requiring reimbursement for reasonable costs). Our preference is to receive data in EIEP3 format, but this is not always the case. Reformatting and cleaning the data, pre- and post-ingestion, creates a significant amount of work, and in some cases, we still need to make adjustments for retailer switching and daylight savings differences.

Key learnings from our experience have been:

- Executive support is essential to ensure data acquisition and use is prioritised by the organisation.
- Commercial, legal, and regulatory expertise is required along with technical expertise.
- EDBs need to budget for the data. It will not come for free from all parties. Some will require the reimbursement of reasonable costs.
- Curating the data and analysing it also requires investment. Realistically value is best unlocked using analytical and data science methods, and through engaged engineers with analytical skills.
- Strict data governance is critical. This gives confidence that the data will only be used as intended, and appropriate safeguards will be put in place

10.4.2 CONSTRAINTS AND OPTIONS

Steps four and five of the planning process (Figure 10.3) identify network constraints throughout the 10-year AMP window based on demand forecast and then develop options for remediation. The constraints and options are identified through a sub-process as shown in the diagram below.

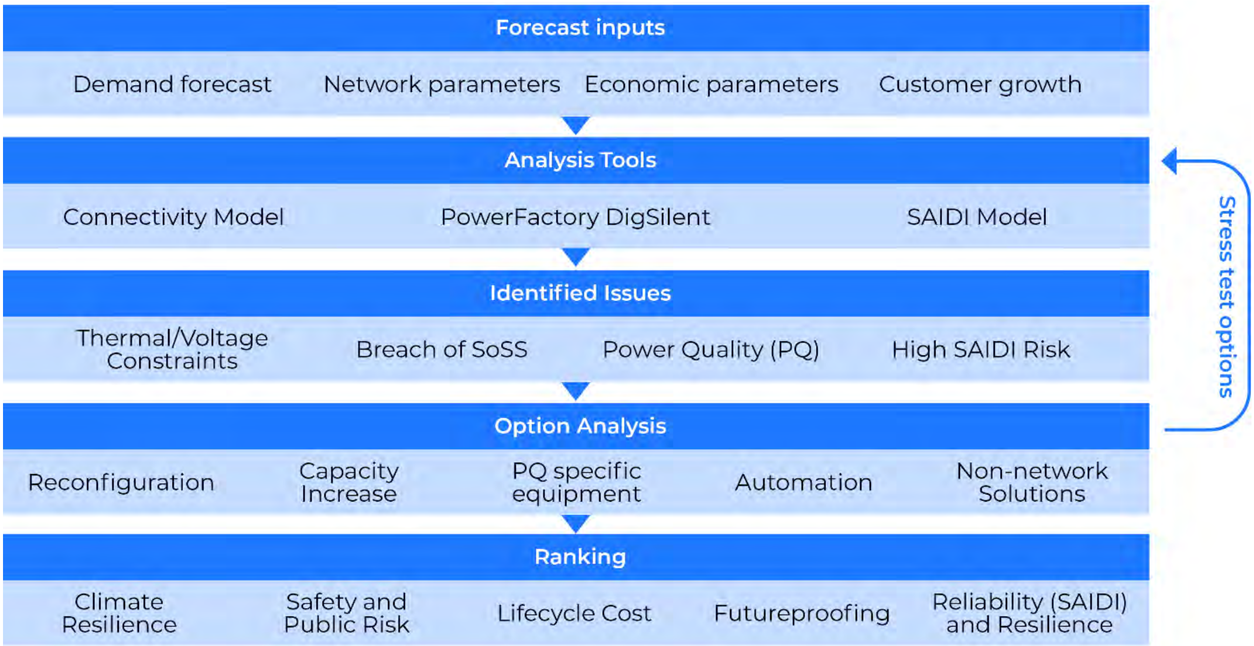


FIGURE 10.6: CONSTRAINTS AND OPTIONS PLANNING PROCESS

The **Network constraint model (Step 4)** uses the demand forecast to identify where and when capacity shortfalls, resulting in a breach of our security of supply standard (Section 7) are expected over the next 10-year period for feeders and zone substations. This model also helps to identify options for alleviating shortfalls by re-routing the network from a location with excess capacity and therefore optimise existing capacity availability. The model captures connectivity of the network and backstopping can be modelled to understand if sufficient capacity is available to avoid a shortfall under contingency conditions (subject to SoSS). We have substantially improved this capability in the last two years by developing automation scripts that run power flow simulations (using Digsilent PowerFactory) for the full 10-year AMP horizon for system health and system backstopping. The outputs identify thermal and voltage constraints on network assets, and for cables and lines specific sub-sections, that cause the constraints are flagged, which expedites the options analysis. In parallel, we will continue to operate our legacy connectivity model to ensure consistency and robustness of process.

Once the type, location and timing of a constraint is identified, **Options Analysis (Step 5)** is undertaken to identify and evaluate the best solution. We use several analytical tools and visualizations to assist with identifying the demand, network constraints and benefits of different options. If more detailed analysis on network constraint or technical assessment of the options is required, we will run specific power flow simulations as required.

A full suite of options is developed. These include:

- Reconfiguration to improve utilization of existing capacity and assets
- Augmentation to add new capacity
- Augmentation to expand the network
- Non-wires alternatives

As required, we will also engage with customers and stakeholders (e.g. community organisations, other infrastructure providers, technology vendors) in this phase to assess additional risks for implementation of options and also identify synergy opportunities.

Non-wires solutions are our preference when feasible within customer, regulatory and economic constraints as they can help customer affordability by deferring or preventing the need for major investment, provide flexibility not available from traditional network solutions, and improve asset utilisation. These alternatives are not limited to options Vector could self-supply but could also be provided 'as a service' by a third-party provider, under contract, if that would come at a lower cost to our customers. Non-wires alternatives can include:

- Real time monitoring and control of DERs through our ADMS and DERMS platforms
- Battery Energy Storage Solutions (BESS) to shave peak demand and/or control voltage
- Microgrids
- Demand side management through customer DER solutions (including third-party service providers), such as smart hot water and smart EV charging
- Increased network automation and interconnectivity
- Improvements to visibility and control of the LV network

To identify the best solutions and optimise and prioritise the network investment, Vector takes a whole of life cycle approach to their evaluation. All the options identified are assessed and ranked based on benefits to network safety, life cycle cost and its impact on customer affordability (initial investment plus ongoing operational costs), reduction to network risk, ability to meet performance requirements and climate resilience (e.g. risk exposure).

To deliver the network generation of network planning tools, Vector is also collaborating with X, formerly Google X, to virtualise our electricity network and develop new grid planning tools in a multi-year partnership (see case study on Grid Planning Tool).

CASE STUDY: GRID PLANNING TOOL

Electricity network planning and customer connections assessments are getting more complex as operational characteristics (e.g. increasingly unpredictable weather patterns, load variation, DER controls) are impacting planning decisions. Thus, the traditional boundary between planning (month-years ahead) and operations (hours-real-time) are blurring. At the same time, customers (primarily large-scale customers today) are demanding more choice and optionality in terms of cost and reliability of connections, and across a variety of potential sites, as the electricity connection cost becomes an important portion of their early-stage business plans (Figure 10-7).

To meet these challenges, a new generation of planning tools are required, which motivated the development of the 'Grid Planning Tool' (GPT) as part of X's Tapestry Platform. GPT is providing a single, virtualized view of the entire electricity system and the tools to run grid simulations for any location and at any time scale. GPT also facilitates the ingestion of relevant Vector data, allows swift and efficient modelling of a large variety of scenarios (e.g. modelling impact of EV/PV/DERS), generates asset planning recommendations out of this and provides a unique representation of constraints to present options to decision-makers (including regulators and customers).

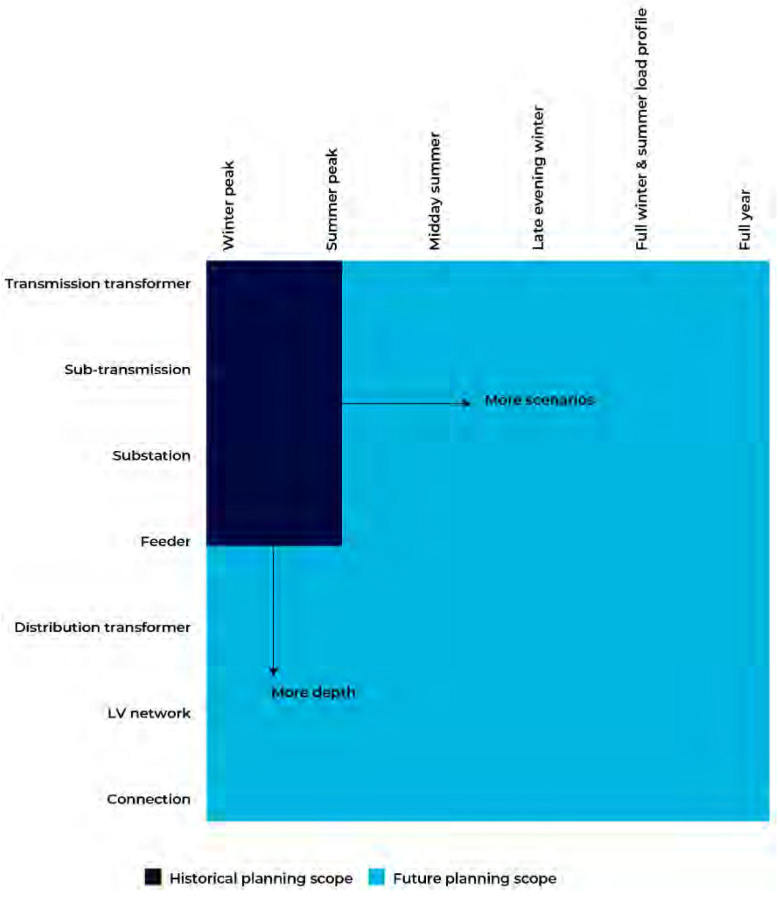


FIGURE 10.7: INCREASING COMPLEXITY OF NETWORK PLANNING IN DEPTH OF NETWORK AND TIME INSTANCES

10.4.3 IMPLEMENTATION

Implementation (Step 6) involves, for both network and non-wires solutions, finalizing the detailed design, obtaining necessary approvals or permits required, construction and commissioning of the project.

Finally, Vector undertakes **Continuous Monitoring (Step 7)** of its network, investments and asset performance to ensure alignment with asset management objectives. The review process ensures the investments are achieving the planned outcome and that Vector continually learns and improves. The requirement for continual monitoring is a feature of Vector's Asset Management System and include:

- Asset Management Control, Review, Audit and Assurance

- Asset Performance and Health Monitoring
- Post Investment Reviews
- Stakeholder Engagement for implementation
- Sustainability impact

Findings from the reviews are fed back into the planning process.

10.5 Signposting opportunities for non-wires alternatives

Vector Networks has successfully deployed six large-scale battery energy storage systems to defer investments in traditional wires solutions. Additionally, we have trialled various NWAs to understand the technology and customer behaviour. Examples include the rollout of 250 SunGenie residential solar-battery programme (2014), the smart hot water trial (part 1: 2018; part 2: 2022), the peak-time rebate trial (2018) and the EV Smart Charging Trial (2019). At the back of these trials, Vector has developed a deep knowledge base around the technical potential of NWAs and has subsequently included the use of NWA to defer network reinforcement into the network planning process. In 2022, we also launched a public registration of interest to find NWAs that could help alleviate a security constraint in the wider Warkworth area (see case study on Registration of Interest for non-wires alternative in Warkworth area).

CASE STUDY: REGISTRATION OF INTEREST FOR NON-WIRES ALTERNATIVE IN WARKWORTH AREA

In January 2022, Vector launched a public registration of interest (RoI) for non-wires alternatives in the Warkworth area. The objective was to engage the local and international market to identify a proven solution that could be deployed cost-efficiently, at scale and in time to alleviate a sub-transmission constraint in the near-term and two zone substation constraints subsequently.

A strong promotion campaign saw high interest from the industry and resulted in 12 potential solutions that met the high-level criteria and were selected for further evaluation. All the solutions Vector received were in response to the RoI (none were pre-scoped or pre-existing). The majority of the non-wires solutions offered were 'technology' solutions (i.e. the provider would install a particular technology that Vector would then own and operate), rather than 'as-a-service' solutions where Vector did not take ownership of any equipment. After extensive analysis and evaluation of all solutions, the assessment criteria showed that none of the solutions would provide a better consumer outcome than a traditional capacity upgrade and so in this case an NWA was not implemented.

Our RoI process was widely followed within the energy industry and by government stakeholders, as it was a high-profile opportunity to integrate a new network solution into the electricity network for New Zealand's largest city, in an area of high growth and customer demand. We learned that:

1) NWAs offer viable alternatives in certain conditions, but the economics are challenging - especially if a technology roll-out at customer premises is required. Also, while DERs are often touted as swift to deploy, in our situation there was no existing or latent flexibility in the area available. Therefore, all solutions required the deployment of new technology, some of which would have required significant levels of sales to mass-market consumers. This means NWA projects require considerate lead times to procure and deploy the equipment, and the roll-out likely needs to be underpinned by multiple revenue streams.
2) The flexibility service market needs building, as today most NWAs on offer are technology solutions, which require innovation funding from EDBs. However, EDBs have very little allowance for funding innovation if not directly linked to business outcomes, which makes it difficult for EDBs to justify these investments under current regulations. New Zealand is lagging other countries in enabling an effective flexibility market. Public funding available to deploy flexibility solutions and grow the market in other countries (e.g. Australia, UK) far exceeds the innovation budgets available in New Zealand.
3) Regulated EDBs need more flexibility in funding as the current fixed 5-year regulatory periods offer little room to change course and swap a CAPEX solution for an OPEX solution. EDBs are still accountable for reliability (SAIDI, SAIFI) and bear the reputational risk of any issues causing outages on the network. However, solutions providers are expecting EDBs to lead the development of the flexibility market. Alternatively, deployment and operation of non-wires solutions can be incentivised by cost-reflective distribution pricing (instead of dedicated OPEX funding), but, depending on the locational granularity of the constraint being managed, may not deliver the performance guarantees EDBs will need to defer investment with confidence.

As part of the options analysis of the network planning process (Step 5), different solutions are evaluated based on cost. However, wires and non-wires alternatives are not directly comparable based on their upfront cost alone, as they have different characteristics (see Table 10-2) and do not provide the same network reinforcement 'service'. In particular:

- Wires (or network) solutions involve reinforcement of the network due to load growth. They eliminate a network constraint for generally 15+ years and have a lifetime of more than 40+ years. The investment in these solutions is typically lumpy 'no-return' or irreversible, which means that, once it is deployed, the solution can't be economically re-sized and means spare capacity is created.
- Non-wires alternatives have very different characteristics – a) the decentralised nature of the solution means that it is adaptable/modular/scalable so that it can be adapted as load changes over time ; b) the technology has shorter lifetime (certainly less than 20 years, but often even less than 10);c) they introduce new performance risks due to customer behaviour and technology (e.g. communication) and ; d) if load growth is high or an unexpected new large customer connects, the need for the wires/network alternative is only deferred, not eliminated, and the deferment period could be much shorter than predicted or contracted (and paid) for.

	WIRES	NON-WIRES
Size of solution/investment	Lumpy	Modular and scalable
Lifetime	40+ years	10-20 years
Deferment of constraint (typical)	>15 years	about 5 years (more possible)
Performance risk	Typical electricity asset risks	Typical asset risks and new customer behaviour, contractual and technology (e.g. communication) risks

TABLE 10-2: COMPARISON OF WIRES AND NON-WIRES CHARACTERISTICS

Hence, a different framework is needed to understand the value of NWAs compared to wires/network solution and assess if an NWA makes sense from an economic perspective. Essentially, an NWA can be considered economic from a societal/customer perspective if the NWA deployment cost is lower than the deferral value of the wires/network investment.

10.5.1 ASSESSMENT FRAMEWORK

To increase our collaboration opportunities with customers and third-party providers, who consider DER projects, this year's AMP signposts the reinforcement projects, where we expect the NWA would be most competitive with network solutions. While our system growth projects have always been reflected in the AMP, this section is our effort to have a simpler, more transparent engagement with customers, communities and potential providers of non-network solutions:

1. Only system growth projects that deliver capacity are suitable (e.g. remove other system growth projects like recloser installations, land purchase, SAIDI project)
2. Focus only on wires projects with capital value larger than $2M over 10 years, reflecting the feasibility of the current NWA market to deliver cost-effective solutions.
3. Generally limited to flat and slow load growth regions as NWAs could significantly defer traditional investment here and deliver higher value
4. Finally, the deferment value is calculated based on load reduction delivered from NWA and the projects with a deferment value greater than $500k are flagged. This deferment value does not include the cost of the NWA nor the risk assessment, but it is a gauge to understand the economic potential. Note that the deferment value calculation captures uncertainty around future so that the specific characteristics described in this subsection are captured. NWAs have different characteristics from an investment perspective. NWAs can scale and adapt to load growth as well as providing the option to 'buy time'/'wait and see how' when dealing with uncertain load growth. Clearly this provides value, and our probabilistic framework captures sensitivities around the following i) future cost uncertainty ii) commissioning year (due to load growth uncertainty) and iii) deferment period (due to technology risk and customer behaviour around non-wires alternatives).

Figure 10-8 illustrates the assessment process and highlights the number of projects in each step of the process.

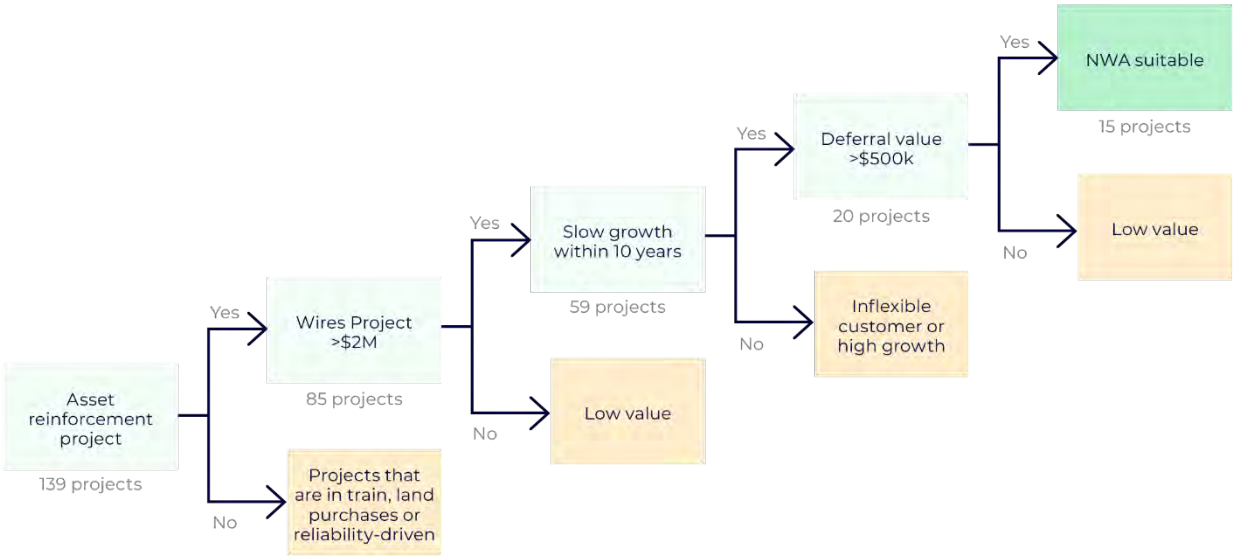


FIGURE 10.8: PROCESS TO IDENTIFY SIGNPOSTED NON-WIRES ALTERNATIVES

10.5.1.1 LIST OF REINFORCEMENT PROJECTS MOST SUITABLE FOR NWA

Our assessment framework has identified 15 projects with suitable characteristics for NWAs (Table 10-3:). This is based on value of deferment. The implementation of an NWA as final solution will depend on NWA cost, customer behaviour and regulatory environment. Key information on all projects are provided in the network planning area section (Section 10.7). For major projects (i.e., more than $1M investment) within next 5 years, more detailed information (including a description of the options considered) are available in Section 10A – Appendix: Growth and Security Projects.

PROJECT NAME	MORE INFORMATION
Chevalier subtransmission upgrade	Section 10.7
East Coast Road second 33/11 kV transformer & 33 kV cable	Section 10.7
Hans Middlemore Cres 11 kV feeder new	Section 10.7
Kingsland substation 110/22 kV reinforcement	Section 10.7
Manly 33/11 kV transformer capacity upgrade	Section 10.7
Manurewa Alfriston Rd 1 1kV feeder new	Section 10.7 & Section 10A
Maraetai subtransmission reinforcement	Section 10.7 & Section 10A
Ranui second 33/11 kV transformer & 11 kV switchgear	Section 10.7
Sabulite 33/11 kV transformer capacity upgrade	Section 10.7
Sandringham third transformer	Section 10.7
Swanson second 33/11 kV transformer	Section 10.7 & Section 10A
Takanini zone substation capacity upgrade	Section 10.7 & Section 10A
Te Atatu 33/11 kV transformer (T1 and T2) capacity upgrade	Section 10.7 & Section 10A
Warkworth South Zone Substation New	Section 10.7 & Section 10A
White Swan zone substation capacity upgrade	Section 10.7

TABLE 10-3: MOST SUITABLE PROJECTS FOR NWAS

Beyond this list there may be opportunities to defer other reinforcement projects if developers or customers are planning on installing a large DER (e.g. battery, generation plant) or a high number of DERs in a highly concentrated area. All our reinforcement projects are listed in this section and a new interactive online map also visually represents them on a map (see case study above on interactive maps).

We invite interested parties to contact us via the details provided on our website in the 'contact us' section (i.e. info@vector.co.nz).

10.6 Monitoring the long-term impact of the Covid-19 pandemic

We continue to monitor impacts from Covid-19, including the long-term persistence of changed behavioural patterns and their impact on electricity consumption. While we have seen digitalisation of society accelerate leading to an increase in data centre connections, increased e-commerce businesses and increased focus on residential areas as a result of working-from-home, we have also seen a decrease in hospitality and retail sectors.

Given that this pandemic was a truly unprecedented event with no evidence in recent history to learn from, predictions about the changes to businesses and the resulting electricity demand are highly speculative. However, the pandemic and the resulting economic recovery certainly increase uncertainty about where and when the network will grow. To ensure that we build what is needed for our customers, our planning response to Covid-19 involves close and frequent monitoring of customer and demand data, while continuously re-evaluating risks and investments from our 10-year plans.

Demand outside the CBD has bounced back to pre-COVID levels after heightened Alert Levels and periods of lockdown ended. However, demand levels in the CBD are still below pre-COVID years.

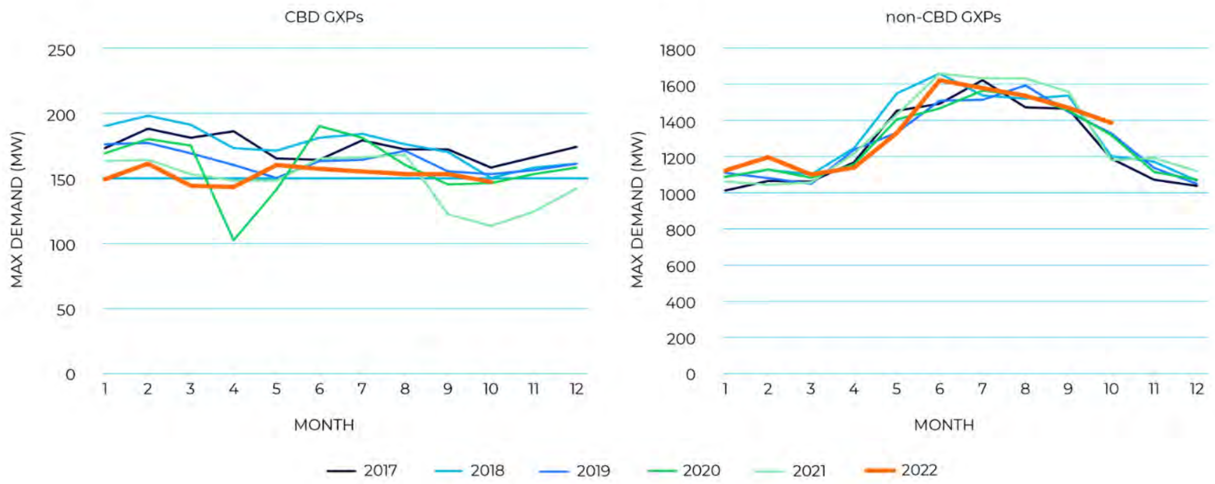


FIGURE 10.9: MONTHLY PEAK DEMAND FOR CBD GXPS AND OTHER GXPS IN AUCKLAND, 2017-22

While this trend could allude to some long-term changes that we will continue to monitor, it is also important to recognise the potential for a 'return to normal' scenario if impacts from Covid-19 restrictions continue to fade. This is supported by continuous connection and works requests in the CBD area, and other significant investments in the CBD, such as the CRL.

We will continue to closely monitor the demand forecast for the CBD to assess the COVID recovery as well as longer-term trends such as hybrid working.

10.7 Network planning areas, reinforcement and replacement

This section sets out Vector's network growth projects for the next 10-year period. The projects are related to the expansion and interconnection of the electricity network to account for Auckland's growth, the densification of suburban areas, the urbanisation of rural areas, and the improved resilience for more isolated rural communities.

The forecast peak winter demand within the AMP period is expected to increase by roughly 1000MW from 1800MW today. This highlights the importance of the next decade of having the right plans, processes and people to succeed. In terms of transport electrification, this AMP demand forecast includes the adoption of light-duty EVs in line with government targets and the electrification of buses (see case study above on powering Auckland's E-Bus Fleet) and Ferry fleet in line with Auckland Transport (AT) plans. Section 2 includes the forecasted peak winter demand to 2050.

To effectively manage investment planning, the network has been divided into geographical planning areas, which correspond to existing individual GXPs or group of GXPs. From the top down each subtransmission and ZSS supplied from the respective GXP is covered under the corresponding planning area. Where a new GXP is forecast to be needed in the future, then this is included in the planning area based on today's view. The figure below shows the network planning areas.

Each Network Planning Area summary describes the physical bounds of the area, the GXP, the ZSSs supplied from the GXP, demand forecast, and network development projects. In developing the projects, Vector takes into account any asset replacements or other investment that is planned for other drivers (such as condition) to ensure a coordinated and efficient approach to expenditure. The options that were considered when assessing each of the material projects are described in the Security and Growth Appendix.

FIGURE 10.10: NETWORK PLANNING AREAS

Auckland's growth is based on the Future Urban Land Strategy laid out in the Auckland Unitary Plan. The Plan covers the areas of Auckland supplied by Vector's Northern and Auckland network regions. Under this plan, the network will need to expand into new undeveloped areas (e.g. Takanini and Wainui) and densify in sparsely developed regions (e.g. Whenuapai). These areas are currently supplied by low-capacity rural feeders and intensification to urban residential levels requires investment in both new ZSSs and distribution reticulation. The spatial distribution of future homes is aligned with the UNIFN for load forecasting (See Section 10.4.1). This includes two main intensification policies: a) The National Policy Statement for Urban Development 2020 (NPS-UD) allows for greater housing density (i.e. buildings of six storeys or more) within walkable distances of the city centre, ten metropolitan centres, and rapid transit stops (train stations and rapid busway stops) and b) the Resource Management Amendment Act 2021 (specifically, the Medium Density Residential Standards) enables three homes of up to three storeys to be built on most residential sites without a resource consent.

Within each planning area, Vector works with Transpower to ensure that demand at each GXP is managed efficiently to avoid over-expenditure on the transmission network when the constraint can be addressed at the distribution network level. This AMP discusses these projects under the subtransmission subheadings below. Any expenditure within the GXP that is not related to Vector owned assets is excluded.

To ensure efficient expenditure, the need for augmentation of any zone substation is assessed with consideration of the support that can be provided from adjacent zone substations. In many cases, multiple zone substations supply an area, so the ability to transfer load between substations to avoid significant expenditure is considered.

The following section describes each of the planning areas and material projects planned for the 10-year period of RY24 through to RY33. For land purchase projects, the expenditure forecast per project is not disclosed, as this would compromise Vector's commercial position during the land purchase process. The total land purchase forecast across 10 years and nine sites is $25M.

10.7.1 WELLSFORD PLANNING AREA

10.7.1.1 OVERVIEW

The Wellsford Planning Area is the most northern in Vector's network; it stretches from Puhoi north to Mangawhai, and Tapora east to Kawau Island. It includes the townships of Wellsford, Warkworth, Matakana, Sandspit, Omaha, Leigh and Snells Beach.

The Wellsford planning area is supplied by Transpower's GXP located at Wellsford. Vector owns three existing zone substations at Wellsford, Warkworth and Snells Beach, with a fourth zone substation at Omaha to be commissioned in 2024. The sub transmission network operates at 33 kV and distribution at 11 kV. The 33 kV overhead subtransmission lines are primarily on private land, with some on rough or heavily vegetated terrain.

The Auckland Unitary plan forecasts significant growth in the Warkworth area. Access to the area will be significantly improved due to the soon to be completed Puhoi to Warkworth motorway and the proposed Warkworth to Te Hana motorway.

The changes to the urban boundary open up significant new land for development, particularly for commercial and industrial development. As a result, the number of ICPs is forecast to grow from 16,000 at present to 25,000 over the next 30 years.

The existing demand is typical for residential customers with a peaky daily load profile and high winter to summer seasonal variation.

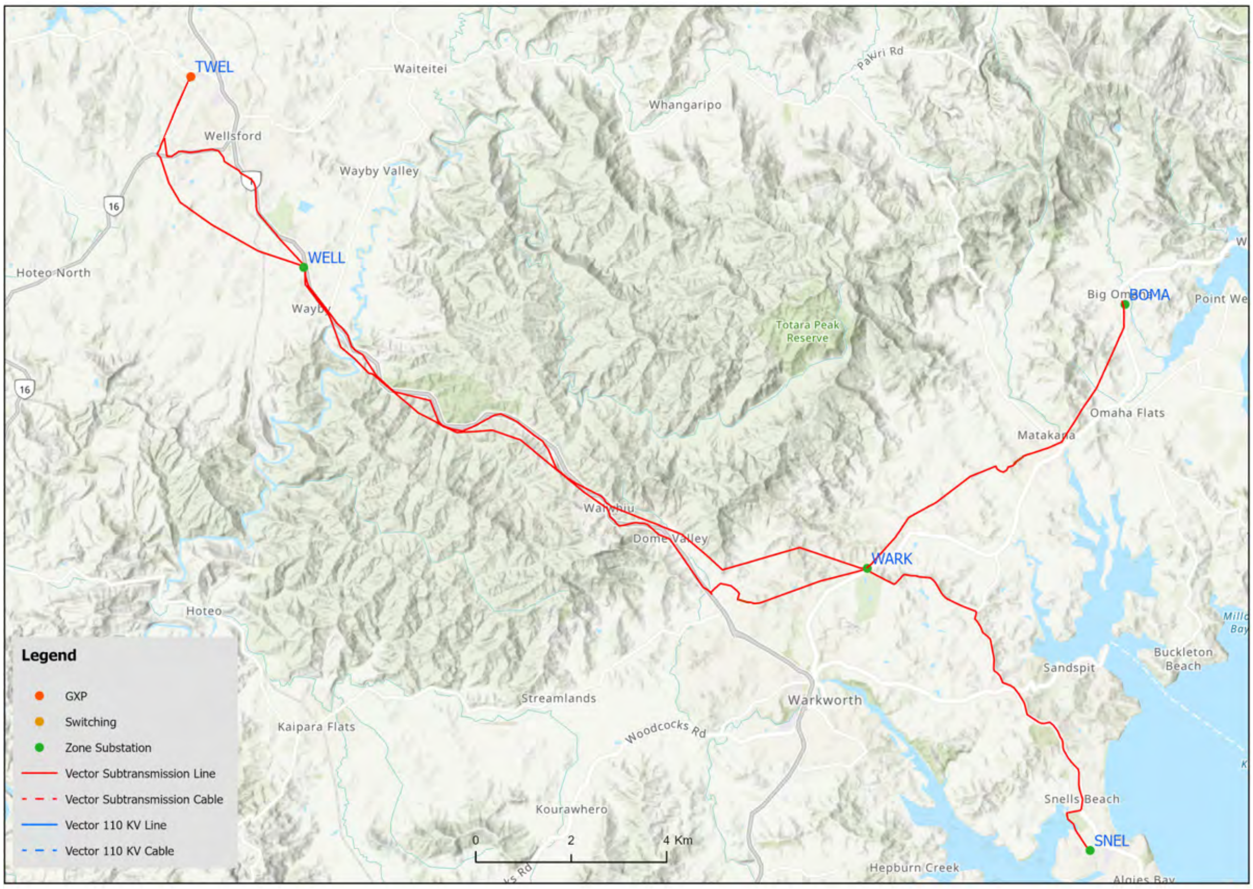


FIGURE 10.11: WELLSFORD SUBTRANSMISSION NETWORK

10.7.1.2 SUBTRANSMISSION

Recent Transmission Planning Reports from Transpower have identified the Wellsford GXP is at its N-1 security limit. Vector has formally engaged with Transpower to investigate options to increase supply capacity.

As shown in Figure 10.11, three 33 kV overhead circuits from Wellsford GXP supply a 33 kV busbar at Wellsford ZSS. From Wellsford ZSS two 33 kV overhead circuits supply Warkworth ZSS from where single 33 kV overhead circuits supply single transformers at Snells Beach and Omaha ZSS.

The 33 kV overhead lines from Wellsford GXP to Wellsford ZSS and Warkworth ZSS were constructed in 1964, are approximately 22 km long (route length) and access to the circuits can prove difficult as the lines traverse complex terrain and multiple privately owned properties.

Due to demand growth, the Wellsford to Warkworth circuits are expected to reach the firm capacity at peak winter evening demand in the near term. To address this constraint, Vector have completed the installation of cable ducts as part of a large-scale project to upgrade State Highway One (SH1) Twin Coast Discovery Highway between Wellsford and Warkworth. To meet the medium-term demand, a new 33 kV cable will be installed in the ducts and switchgear to connect it to the network.

Due to high load growth expectation in the area, the medium-term area plan is to establish a new zone substation to the west of Warkworth and in the longer term another at Mahurangi to the north of Warkworth. The Mahurangi site will initially be supplied at 33 kV but with the ultimate objective of being supplied at 110 kV. Hence, the SH1 cable ducts are designed for 110 kV cables.

In accordance with Vector's Symphony strategy, steps have been taken to use non-wires solutions to reduce the peak demand on the existing subtransmission circuits, thereby delaying the need for reinforcement. These strategies included the installation of Battery Energy Storage Systems (BESS) at Snells Beach (2.5 MW / 6 MWh) and Warkworth South (2.0 MW / 4.8 MWh) to flatten the demand profile.

10.7.1.3 ZONE SUBSTATIONS

Wellsford GXP supplies three ZSSs: Wellsford (2 transformers), Warkworth (3 transformers) and Snells Beach (single transformer). A fourth ZSS Omaha (single transformer initially) is being commissioned in 2023 at Big Omaha, which is centrally located between the townships of Leigh, Omaha and Matakana.

Warkworth ZSS, Snells Beach ZSS and the new Big Omaha ZSS will operate as a combined group providing inter zone substation security. In assessing the ZSS security for the purposes of this AMP it is assumed new Big Omaha ZSS has been completed.

Battery Energy Storage Systems (BESS) with a total capacity of 4.5 MW have been installed in 2019 at Snells Beach and Warkworth South to reduce the network peak demand.

The table below shows that Snells Beach and Warkworth are expected to exceed transformer capacity in 2024 and 2027, respectively. Snells Beach and Warkworth peak demand can be managed by the BESS in the short term. The constraints will be resolved by constructing a new ZSS at Sandspit Rd in 2025 and at Warkworth South in 2029 and redistribution of the load between the group of five substations.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Big Omaha	RES	0.0	6.8	6.9	7.0	7.0	7.3	7.6	7.9	8.1	8.4	8.9
Winter	Snells Beach	RES	7.6	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Winter	Warkworth	RES	23.0	16.8	17.4	18.0	18.8	20.3	21.7	23.1	24.5	26.0	28.7
Winter	Wellsford	RES	8.1	8.2	8.3	8.4	8.5	8.8	9.2	9.5	9.9	10.2	10.9

TABLE 10-4: WELLSFORD LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.1.4 DISTRIBUTION NETWORK

The distribution network in this planning area covers a very large rural area that contains the longest 11 kV rural overhead distribution circuits within Vector's network. The long feeders are susceptible to outages, resulting in poor reliability, and poor power quality.

To address the reliability and power quality issues Vector has identified a number of initiatives using both network and non-wires solutions. The new Omaha ZSS (refer to the zone substation section above) will increase distribution feeder capacity to serve the greater Matakana, Leigh, and Omaha areas and, by shortening the feeder lengths, improve the quality of supply and reliability performance to these areas.

In addition, Vector has installed a 1.149 MW / 1.254 MWh BESS at Tapora to provide improved quality of supply to the Tapora Peninsula, an emerging avocado growing area currently supplied by a long spur feeder.

A new voltage regulator in Te Arai will improve power quality and resolve backstopping constraints.

A recently commissioned zone substation (Kaukapakapa ZSS) on the southern boundary has provided significant feeder backup capacity on the Kaipara Flats feeders and further opportunities for quality of supply improvements.

10.7.1.5 CONSTRAINTS AND NETWORK REINFORCEMENT

The following network reinforcement projects are planned for this area.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Project coordinated with third party	Wellsford to Warkworth 110 kV future proof ducts	FY24	1.1[1]
Te Ari power quality and SoSS breaches	Te Arai 11 kV voltage regulator	FY24	0.4
Wellsford – Warkworth subtransmission breaches SOSS	Wellsford ZSS to Warkworth 33 kV subtransmission cable new – Wellford end	FY24	7.6[1]
	Wellsford ZSS to Warkworth 33 kV subtransmission cable new – Warkworth end		4.4
	Wellsford 33 kV switchgear replacement. Related to the Wellsford-Warkworth subtransmission upgrade		2.8[1]
Future constraints on the 33 kV and 11 kV networks	Land procurement for a future 33/11 kV Mahurangi ZSS and 110/33 kV bulk supply substation	FY25	Not discl.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Transformer capacity at Warkworth ZSS and Snells Beach ZS	New Zone Substation - Sandspit	FY25	8.5
Warkworth area transformer capacity breaches SoSS	New Zone Substation - Warkworth South	FY29	
Sub-transmission circuits to Warkworth breaching SoSS under N-1 conditions	Wellsford ZSS to Warkworth 2nd 33 kV SUBTRANSMISSION cable new	FY34	5.0[2]

TABLE 10-5: WELLSFORD CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

[2] Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.2 SILVERDALE PLANNING AREA

10.7.2.1 OVERVIEW

The Silverdale planning area extends from Albany north to Waiwera, and Whangaparaoa west to Helensville and the west coast. The highest population density is to the east of State Highway 1 (SH1) and comprises the Whangaparaoa, Gulf Harbour, Orewa, Millwater, Red Beach, and Silverdale areas. A MW-scale generation facility from landfill is operating in the area. New medium density developments are forecast to expand westwards from Millwater towards Wainui and Dairy Flat.

The Auckland Unitary plan forecasts significant population growth within the Orewa urban area, primarily due to the increased urban boundary to allow for a planned population increase of 12,000 over the 10-year AMP period. The Unitary Plan forecasts 5,800 new residential ICPs plus industrial and commercial growth, which will increase demand by 14 MW (excluding potential major customers) over the next 10 years.

Significant new land is available for commercial and industrial development with one new large customer identified.

To meet the growing electricity demand primarily due to population growth, a new zone substation at Kaukapakapa has been commissioned in 2020 and capacity upgrades have been completed at Orewa ZSS and Spur Road ZSS.

FIGURE 10.12: SILVERDALE SUBTRANSMISSION NETWORK

10.7.2.2 SUBTRANSMISSION

The area is supplied from the Silverdale GXP. The subtransmission network operates at 33 kV and consists of predominately overhead lines. The 33 kV network is a primarily meshed with only the Gulf Harbour ZSS supplied by a radial line. The network includes two long overhead lines from Silverdale to Helensville.

Vector has identified that the new residential and commercial developments set out by the Auckland Unitary plan will create constraints on the subtransmission network that will breach the SoSS. The constraints will occur under normal operating conditions (N) in 2030, and in the case where a subtransmission line is out of service (N-1), the constraints will occur in 2025 and 2033 if one of the Silverdale – Orewa circuits or the Silverdale – Manly circuits are out of service, respectively. To resolve these constraints, Vector has scheduled projects to replace sections of older low-capacity cable.

10.7.2.3 ZONE SUBSTATIONS

Silverdale GXP supplies five two-transformer ZSSs at Helensville, Manly, Red Beach, Orewa and Spur Road. Gulf Harbour and Kaukapakapa are single transformer substations.

A new zone substation at Millwater (single transformer initially) is planned to resolve the capacity constrained expected as a result of the new residential development on the western side of SH1 towards Wainui. Vector has a suitable site and has installed subtransmission ducts.

A major customer facility was commissioned in FY22 with future expansion in planning. An e-ferry charging station is in planning at Gulf Harbour.

There are no constraints identified at any of the zone substations.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Gulf Harbour	RES	9.1	9.2	9.3	9.4	9.5	12.0	12.3	12.6	12.9	13.2	13.7
Winter	Helensville	RES	11.2	11.3	11.4	11.5	11.6	12.0	12.4	12.8	13.3	13.7	14.4
Winter	Kaukapakapa	RES	6.0	6.1	6.2	6.2	6.3	6.5	6.7	7.0	7.2	7.4	7.7
Winter	Manly	RES	19.5	19.6	19.7	19.7	19.8	20.4	21.0	21.6	22.1	22.7	23.7
Winter	Orewa	RES	19.5	20.4	21.3	22.2	23.1	24.7	26.3	27.8	29.4	31.0	33.3
Winter	Red Beach	RES	22.0	23.3	25.0	26.7	27.9	28.8	29.6	30.4	31.2	32.0	33.3
Winter	Spur Road	RES	13.4	14.0	14.6	15.2	16.4	17.4	18.4	19.5	20.5	21.5	23.4

TABLE 10-6: SILVERDALE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.2.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and underground in the urban areas. The rural distribution network covers a very large rural area that contains long overhead distribution circuits. The long feeders are susceptible to outages, resulting in poor reliability, and poor power quality. The recently completed Northern SAIDI Initiative Makarau project was carried out to address these reliability issues in the Kaukapakapa area.

Distribution network constraints mean the new Millwater ZSS and associated distribution network reinforcement will be required to provide capacity and maintain distribution feeder security to the growing greenfields urban development areas west of Orewa, in Wainui, Milldale and Dairy Flat.

The Waka Kotahi PenLink highway project in Whangaparaoa will provide an opportunity to install a new 11 kV cable on a new bridge across the Weiti River and improve security of supply to the Whangaparaoa peninsula.

10.7.2.5 CONSTRAINTS AND NETWORK REINFORCEMENT

The following network reinforcement projects are planned for this area.

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Capacity for new point load	Dairy Flat land purchase for ZSS	FY25	Not discl.
Forecast breach of SoSS on the subtransmission network under N-1 scenarios	Orewa ZSS Subtransmission Cable Reinforcement	FY25	1.8
Reliability	South Head Permanent Standby Generation	FY25	1.3
Insufficient security of supply on the Whangaparaoa peninsula (project timing determined by external roading project)	PenLink 11 kV reinforcement	FY28	0.6
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	New Zone Substation - Millwater T1	FY28	12.0
Capacity and security of supply for Dairy Flat and surrounding areas	Dairy Flat ZSS 3rd transformer and subtransmission circuits	FY29	19.0
Load forecast breaches SoSS	Manly 33/ 11 kV transformer capacity upgrade	FY32	6.0
Load forecast breaches SoSS on Hibiscus Coast area	Orewa 11 kV Hibiscus Coast reinforcement	FY32	1.6
Load forecast breaches SoSS in West Hoe Heights, Orewa	Orewa 11 kV West Hoe Heights reinforcement	FY33	0.6
Forecast breach of SoSS on the subtransmission network under N-1 scenarios	Silverdale GXP Spur Rd & Manly Subtransmission Cable Reinforcement	FY33	2.0

TABLE 10-7: SILVERDALE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.3 HENDERSON PLANNING AREA

10.7.3.1 OVERVIEW

The Henderson area extends from Riverhead, Whenuapai, Hobsonville and Te Atatu westwards through Ranui, Swanson, Henderson Valley, and the Waitakeres to the west coast from Muriwai down to Te Henga.

The urban part of the region is one of the major growth areas in the Auckland region, with large population growth of 39,000 over the next 10 years projected in the Auckland Unitary plan. The growth is driven by major residential brownfield developments at Hobsonville Point extending northward towards Whenuapai, Riverhead, and Kumeu, and to Westgate and Redhills in the west. This growth equates to approximately 15,000 net additional dwellings and an approximate additional load of 30 MW over the next 10 years.

A number of large-scale data centres have been recently commissioned or are in construction or planning. This may result in over 120 MVA in installed capacity in a concentrated area around Westgate/Hobsonville.

E-ferry charging stations are in planning at West Harbour and Hobsonville.

Significant new land is available for commercial and industrial development plus four major customer sites identified or committed. Other important load centres include the New Zealand Air Force Whenuapai base and Waitakere Hospital.

A new zone substation at Hobsonville Point was commissioned in 2019 with a co-located 1 MW / 2 MWh BESS to provide peak demand support.

Load will be transferred to Albany GXP from Henderson GXP in order to manage demand on Henderson.

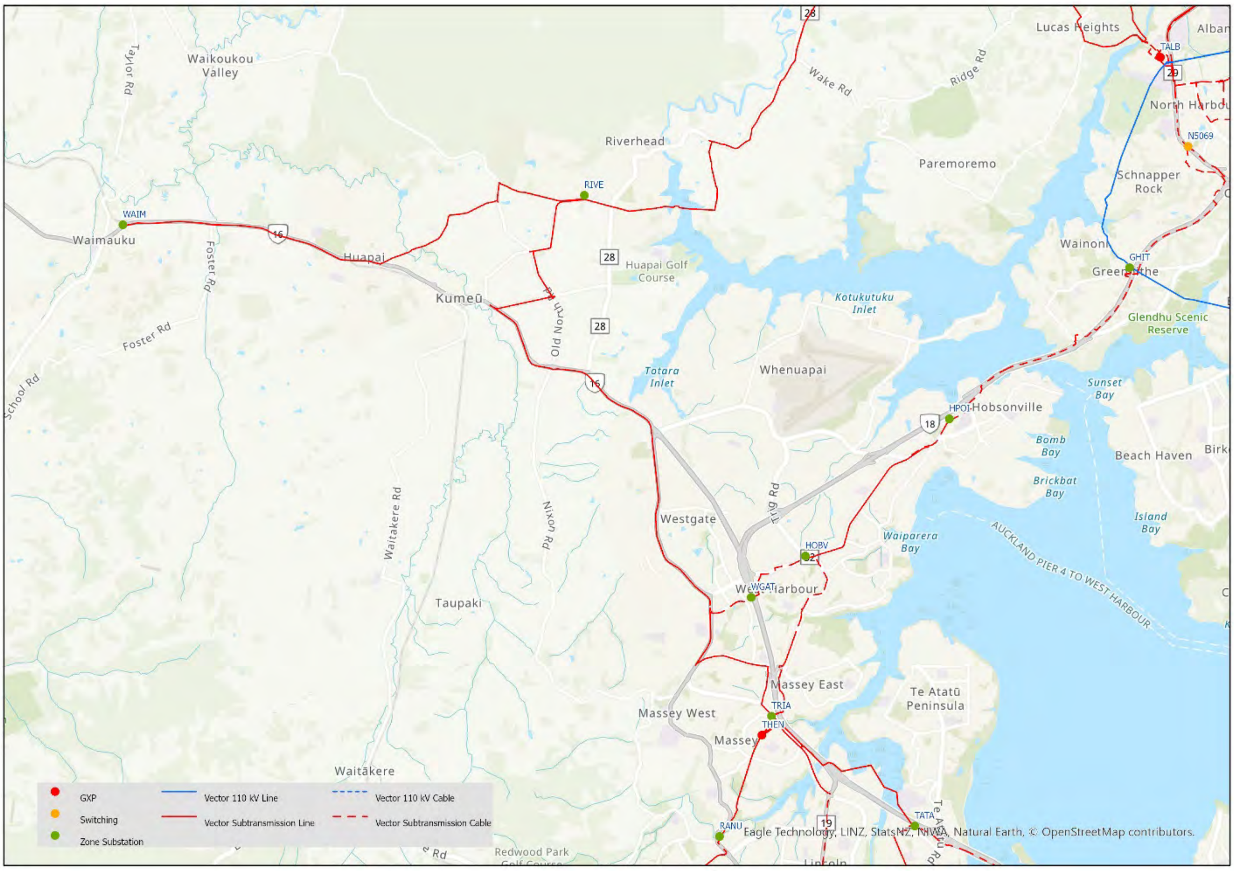


FIGURE 10.13: HENDERSON SUBTRANSMISSION NETWORK

10.7.3.2 SUBTRANSMISSION

The area is supplied from the Henderson GXP. The subtransmission network operates at 33 kV and consists of predominately overhead lines.

Vector has identified that the new residential and commercial developments set out by the Auckland Unitary plan will create constraints on the subtransmission network that will breach the SoSS. The constraints will occur under normal operating conditions (N) in 2028 on the Henderson to Hobsonville line and in 2030 on the Hobsonville to Hobsonville Point line. In the case where a subtransmission line is out of service (N-1), the constraints will occur in 2023 and 2027 if one of the two circuits on either the Henderson to Hobsonville line is out of service or the Henderson to Westgate Line is out of service, respectively.

The Albany-Greenhithe subtransmission upgrade (discussed in section 10.9.5 below) will add 33 kV capacity and security of supply into the Henderson Planning Area from the north and alleviate the Hobsonville constraints.

The 33 kV subtransmission to Waimauku zone substation is a single overhead line and therefore, even though it has two transformers, the substation is on N security. This is not a major risk as the overhead line is accessible and repairs can be carried out quickly to fully restore supplies and maintain compliance with the SoSS. A SafeRoads project for South Highway 16 (SH16) is in progress and Vector is taking the opportunity to lay ducts for a future second 33 kV circuit to Waimauku ZSS, and a new 11 kV cable to increase security of supply to Kumeu, Huapai and Waimauku.

As the demand growth of recent developments (including data centres) materialises, the implications for Grid Exit Point capacity will emerge. Options to increase capacity from the national grid are being actively investigated with Transpower.

10.7.3.3 ZONE SUBSTATIONS

Henderson GXP supplies 10 zone substations of which four are single-transformer ZSSs, namely Simpson Road, Swanson, Ranui, and Woodford and six are two-transformer ZSSs, namely Triangle Road, Te Atatu, Westgate, Hobsonville, Hobsonville Point, and Riverhead.

The demand forecast shows that there are expected to be breaches of the SoSS at Ranui ZSS (2026) and Swanson ZSS (2026). As these zone substations are adjacent to each other, Vector has identified the preferred solution to be the installation of a second transformer at Swanson ZSS and network reconfiguration to balance load.

Transformer capacity constraints are forecast at Riverhead ZSS and Te Atatu ZSS, and transformer replacement projects are schedule for commissioning in FY25 and FY30 respectively.

Demand growth and a new major customer connection are driving an emerging constraint in Whenuapai and Redhills. The preferred solution is to construct new zone substations at Whenuapai and Redhills to provide the required capacity and avoid capacity upgrades at Westgate, Hobsonville and Hobsonville Point ZSS.

An 11 kV regulator project in construction will improve backstopping to Waimauku ZSS and improve SAIDI for the Muriwai area.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Hobsonville	RES	14.9	16.4	18.2	19.9	21.3	22.4	23.4	24.4	25.4	26.4	27.6
Winter	Hobsonville Point	RES	16.2	28.2	31.6	36.2	40.6	42.2	43.8	45.4	47.0	51.4	53.3
Winter	Ranui	RES	14.5	15.1	15.7	16.2	16.8	17.7	18.6	19.5	20.4	21.3	22.7
Winter	Riverhead	RES	12.7	14.1	16.2	17.1	18.0	19.4	20.8	21.5	22.3	23.0	24.7
Winter	Simpson Road	RES	5.1	5.1	5.2	5.3	5.3	5.5	5.7	5.8	6.0	6.1	6.4
Winter	Swanson	RES	11.4	11.5	11.6	13.1	13.2	13.5	13.9	14.2	14.6	14.9	15.6
Winter	Te Atatu	RES	22.2	22.4	22.5	22.7	22.8	23.5	24.3	25.0	25.7	26.4	27.6
Winter	Triangle Road	RES	15.9	16.8	15.3	15.5	15.6	16.2	16.7	17.2	17.7	18.2	19.1
Winter	Waimauku	RES	12.6	13.0	13.3	13.7	14.1	14.9	15.7	16.4	17.2	18.0	19.7
Winter	Westgate	COM	15.9	20.2	22.1	28.5	30.1	31.6	33.1	34.6	36.1	37.6	39.1
Winter	Woodford	COM	8.6	11.0	11.1	11.2	11.3	11.6	12.0	12.3	12.6	12.9	13.5

TABLE 10-8: HENDERSON LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.3.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and a combination of overhead and underground in the urban areas. The rural distribution network covers a very large rural area that contains long overhead distribution circuits.

The forecast growth will cause constraints on the 11 kV network will be addressed by the new zone substations at Whenuapai and Redhills. Vector's analysis showed that a new substation provided better value and feasibility than augmenting existing feeders or installing new feeders.

Continuing commercial development at the Westgate shopping centre is resulting in capacity constraints which will be addressed by the Fred Taylor Drive 11 kV reinforcement project, and later by the Redhills ZSS.

Development at Waitakere Hospital will result in a feeder capacity shortfall and a cable replacement project is planned.

10.7.3.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Capacity constraint on the distribution network	Fred Taylor Drive 11 kV reinforcement	FY24	3.9
Project coordinated with Waka Kotahi roadworks	SH16 Kumeu to Brigham Creek future proofing ducts	FY24	0.1[1]
Project coordinated with Auckland Transport roadworks	SH 16 Access Rd future-proofing ducts	FY24	0.1[1]
Constraints on the 11 kV distribution network in the Redhills area; Redhills major customer	Henderson GXP Redhills subtransmission future-proofing ducts	FY24	3.0
Constraints on the 11 kV distribution network in the Redhills area	Redhills Zone Substation land purchase	FY25	Not discl.
	New Redhills Zone Substation	FY29	15.0
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	Riverhead 33/11 kV transformer capacity upgrade and 11 kV switchgear	FY26	13.5
Waimauku backstop shortfall; Whenuapai 11 kV feeder capacity; Whenuapai major customer	Whenuapai Zone Substation land purchase	FY24	Not discl.
	New Whenuapai ZSS	FY27	24.0[1]
Simpson ZSS, Ranui ZSS and Swanson ZSS zone substation breaches SoSS	Swanson second 33/11 kV transformer	FY26	8.3
Henderson subtransmission network capacity constraint in 2028	Henderson GXP Ranui subtransmission Cable Replacement	FY27	0.5
Project coordinated with Waka Kotahi roadworks	SH16 Huapai to Waimauku reinforcement	FY26	3.7[1]
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	Waimauku ZSS 33/11 kV T2 transformer capacity upgrade and 11 kV switchgear	FY28	6.1
	New Redhills Zone Substation	FY29	15.0
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	Te Atatu 33/11 kV (T1 and T2) transformer capacity upgrade	FY30	6.0
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	Ranui second 33/11 kV transformer & 11 kV switchgear	FY30	7.6

TABLE 10-9: HENDERSON CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

10.7.4 HEPBURN PLANNING AREA

10.7.4.1 OVERVIEW

The Hepburn area includes Avondale, Te Atatu South, New Lynn, Green Bay, Titirangi and Laingholm, extending west to Piha and south to Parau, Cornwallis and Huia. Relatively low growth is forecast except for a major KiwiRail traction supply connection to the GXP, and pockets of re-development around the old Brickworks site in New Lynn and the Sabulite areas.

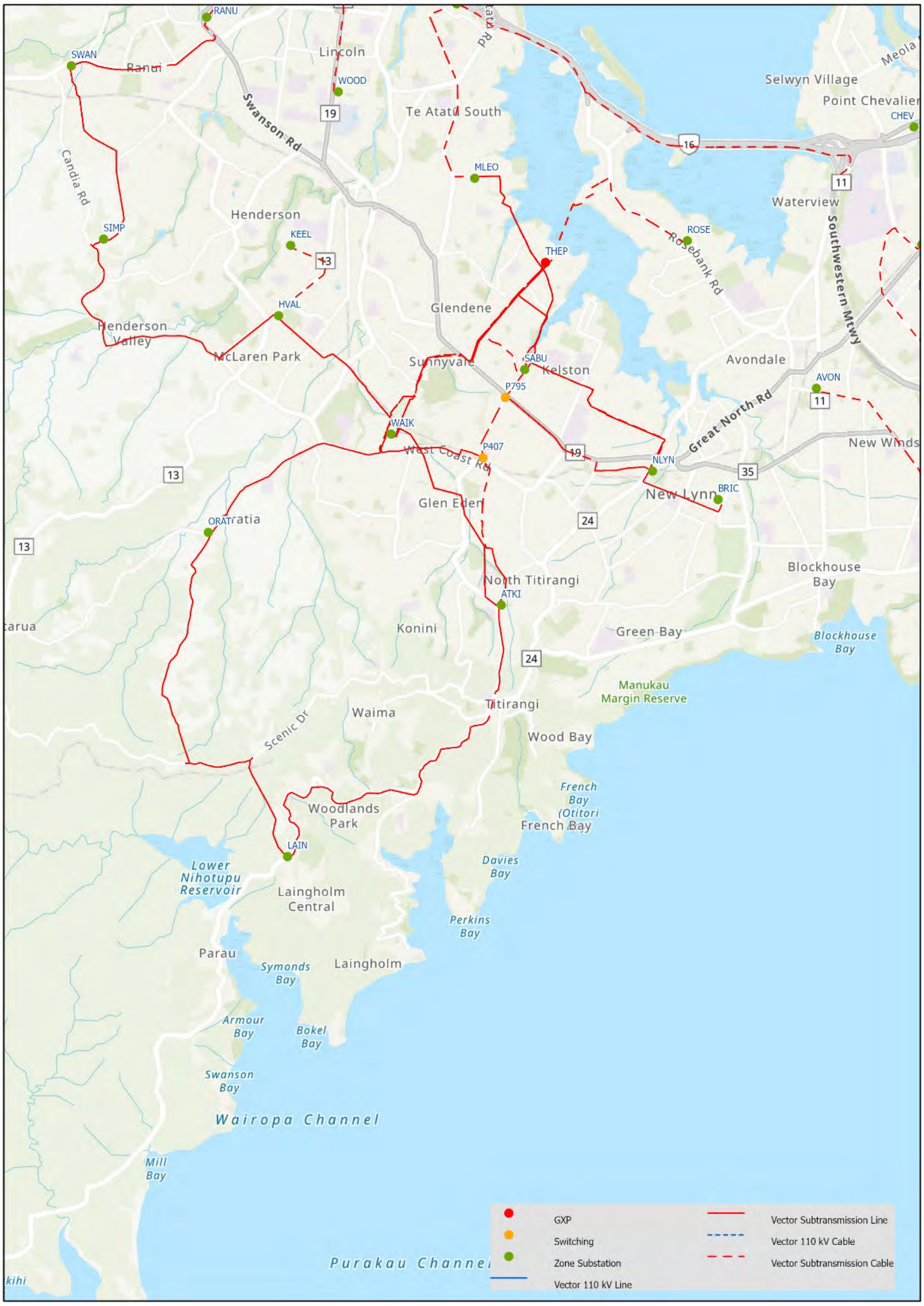


FIGURE 10.14: HEPBURN SUBTRANSMISSION NETWORK

10.7.4.2 SUBTRANSMISSION

The area is supplied from the Hepburn GXP. The subtransmission network operates at 33 kV and consists of predominately overhead lines. The area mostly consists of low-density urban terrain, except for the subtransmission rings to Atkinson Road, Oratia and Laingholm subtransmission loop which traverses hilly and heavily vegetated terrain resulting in higher impact to reliability.

While there is low growth forecast, Vector has identified that there are expected to be constraints that occur under N-1 conditions when specific subtransmission lines are out of service. The constraints are all forecast for the end of the AMP period in 2030 and will occur if one of the four Hepburn GXP to Waikaukau ZSS circuits or the Waikaukau ZSS to Atkinson ZSS line is out of service. Each of these constraints will cause a back-up circuit to exceed its rated capacity. The Hepburn to Waikaukau constraints will be resolved by cable replacements planned under asset replacement programmes.

10.7.4.3 ZONE SUBSTATIONS

Hepburn GXP supplies 10 zone substations of which four are single-transformer ZSSs, namely Oratia, Brickworks, Waikaukau, and McLeod Road and six are two-transformer ZSSs, namely Keeling Road, Henderson Valley, Atkinson Road, Laingholm, Sabulite Road, and New Lynn.

Capacity constraints are forecast at Brickworks, Sabulite and Waikaukau zone substation.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Atkinson Road	RES	18.1	18.3	18.4	18.5	18.6	19.2	19.8	20.4	21.0	21.6	22.5
Winter	Brickworks	COM	11.4	14.4	14.8	15.2	15.6	16.3	18.7	19.6	20.4	21.1	22.2
Winter	Henderson Valley	COM	16.1	16.4	16.7	17.0	17.3	18.1	19.0	19.8	20.6	21.5	22.9
Winter	Keeling Road	RES	13.7	14.0	14.2	14.4	14.7	15.2	16.2	16.8	17.4	17.9	18.9
Winter	Laingholm	RES	9.2	9.2	9.2	9.3	9.3	9.5	9.7	9.9	10.2	10.4	10.7
Winter	McLeod Road	COM	9.4	9.5	9.5	9.6	9.7	10.0	10.4	10.7	11.0	11.4	11.9
Winter	New Lynn	RES	13.8	14.2	14.5	14.9	15.2	16.0	16.7	17.5	18.2	19.0	20.2
Winter	Oratia	RES	5.3	5.3	5.3	5.3	5.3	5.5	5.6	5.7	5.9	6.0	6.2
Winter	Rosebank	COM	21.4	22.4	23.4	24.4	25.4	26.4	27.4	28.4	29.4	30.4	31.4
Winter	Sabulite Road	COM	21.2	21.3	21.5	21.6	21.8	22.5	23.2	23.9	24.6	25.3	26.5
Winter	Waikaukau	COM	7.5	7.5	7.5	7.6	7.6	7.8	7.9	8.1	8.3	8.5	8.8

TABLE 10-10: HEPBURN LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.4.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and a combination of overhead and underground in the urban areas. The distribution network covers a very large rural area that contains long overhead line which present reliability challenges.

Reliability and resilience issues have been identified on the single radial 11 kV overhead feeder supplying the greater Piha area. To address this issue, temporary standby generation has been installed and at Piha, a cable project linking 11 kV feeders along Scenic Drive has been completed and a long-term generation solution is in planning.

Feeder capacity constraints have been identified in the Brickworks and Keeling ZSS areas. A recently completed project reinforced the Brickworks network and future projects include construction of a new Brickworks feeder (Clark St) and cable replacement in the Keeling network (Railside Dr).

10.7.4.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Reliability	Piha Permanent Standby Generation	FY25	1.6
Transformer capacity	Brickworks 33/11 kV 2nd transformer, 11 kV switchgear replacement, and new 33 kV cable	FY28	12.5
Feeder capacity	Brickworks new 11 kV feeder Clark Street	FY28	1.4
Subtransmission breaches SoSS under N-1 conditions	Atkinson Rd subtransmission cable reinforcement	FY28	0.1
Transformer capacity	Waikaukau 33/11 kV 2nd transformer	FY29	2.5
Transformer capacity	Sabulite 33/11 kV transformer capacity upgrade	FY32	6.5
Feeder capacity	Railside Ave 11 kV reinforcement KEEL K06	FY32	1.1

TABLE 10-11: HEPBURN CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.5 ALBANY PLANNING AREA

10.7.5.1 OVERVIEW

The Albany Planning Area extends from Totara Vale and Forrest Hill north to Fairview Heights, and the East Coast Bays from Castor Bay to Torbay, also including Paremoremo, Coatesville, and Dairy Flat. Important load centres include Watercare Rosedale treatment facility and the Massey University campus.

The major residential growth areas are Long Bay and Glenvar and steady densification of commercial areas (taller buildings and higher density construction) is driving an increase in demand in existing areas in Albany (i.e. McKinnon ZSS) and Rosedale. The overall growth in these areas 2033 is forecast to be 30+ MVA. Additionally, a few large commercial facilities will be connected in the area. Load will also be transferred to Albany GXP from Henderson GXP in order to manage demand on Henderson.

A major customer facility is in planning, with a direct connection to the GXP.

FIGURE 10.15: ALBANY SUBTRANSMISSION NETWORK

10.7.5.2 SUBTRANSMISSION

The area is supplied from the Albany GXP. The subtransmission network operates at 110 kV and 33 kV and consists of predominately overhead lines in the rural areas and underground in the urban areas. The area mostly consists of low-density urban subdivisions, with a number of commercial centres.

Waimauku ZSS is supplied from Albany, however, it is included in the Henderson planning area as it is closer to Henderson GXP and supplies customers considered to be within the Henderson planning area. The long-term plan is to supply Waimauku ZSS from Henderson GXP or from a new GXP at Huapai.

A constraint on the Albany GXP to Greenhithe ZSS circuit is forecast and a cable installation project is scheduled by FY25, followed by a project to convert one of the Albany-Wairau 110 kV lines to 33 kV for a second Albany-Greenhithe circuit.

The wider Rosedale area is supplied by an interconnected subtransmission network which connects 9 ZSS. Constraints on the Albany GXP to Bush Rd ZSS circuits and Bush Rd ZSS to Sunset Rd ZSS are forecast. The preferred solution is to reinforce the existing Albany GXP to Rosedale ZSS circuit and install a second circuit, partially re-using two of the Albany-Wairau 110 kV lines at 33 kV.

10.7.5.3 ZONE SUBSTATION

Albany GXP supplies 12 zone substations of which five are single-transformer ZSSs, namely Coatesville, Greenhithe, Waiake, Torbay and East Coast Road and seven are two-transformer ZSSs, namely Waimauku, McKinnon, Browns Bay, Rosedale, Bush Road, Sunset Road, and Forrest Hill. A project is in delivery to install a second transformer at Coatesville.

A capacity constraint has been identified at East Coast Road ZSS. A project to install a second transformer and subtransmission cable is planned for commissioning in FY32. Load transfers will manage peak demand until then.

A capacity constraint has been identified at McKinnon ZSS in the early 2030s. Increasing capacity at this site is challenging. A project to replace the transformers at the adjacent Bush Rd ZSS and transfer load away from McKinnon, is planned for commissioning in FY34.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Browns Bay	RES	15.7	15.8	15.9	16.1	16.2	16.8	17.3	17.9	18.4	19.0	20.0
Summer	Bush Road	COM	22.1	22.0	21.9	21.8	21.7	21.7	22.0	22.4	22.8	23.2	23.6
Winter	Coatesville	RES	10.9	11.0	11.0	11.0	11.1	11.4	11.7	12.0	12.3	12.7	13.7
Winter	East Coast Road	RES	18.4	19.0	19.1	19.3	19.4	19.9	20.5	21.0	21.6	22.1	23.1
Winter	Forrest Hill	RES	16.1	16.2	16.3	16.4	16.4	16.9	17.3	17.7	18.1	18.6	19.3
Winter	Greenhithe	RES	11.0	11.1	11.2	11.3	11.4	11.8	12.2	12.6	12.9	13.3	13.9
Winter	McKinnon	RES	19.0	19.6	25.0	25.6	26.2	27.3	28.4	29.5	30.5	31.6	33.3
Winter	Rosedale	COM	15.2	15.3	15.4	15.5	20.7	21.4	22.0	24.1	24.5	25.0	25.7
Winter	Sunset Road	COM	14.2	14.4	14.5	14.6	14.8	15.5	16.1	16.8	17.5	18.2	19.4
Winter	Torbay	RES	9.3	9.4	9.5	9.6	9.7	10.0	10.3	10.6	10.9	11.2	11.7
Winter	Waiake	RES	8.5	8.6	8.6	8.7	8.8	9.1	9.4	9.7	10.0	10.2	10.8

TABLE 10-12: ALBANY LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.5.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and underground in the urban areas.

A forecast security of supply shortfall on a Rosedale ZSS feeder will be addressed by a project to create a new feeder (Triton Drive).

10.7.5.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Rosedale feeder breaches SoSS	Rosedale new 11 kV Triton Drive feeder	FY24	1.9
Project coordinated with Waka Kotahi roadworks	Rosedale Rd (Triton Dr to Tawa Dr) future-proofing ducts for the Albany GXP Rosedale subtransmission cable reinforcement	FY25	2.1
Albany subtransmission breaches SoSS	Albany GXP Greenhithe new Subtransmission cable	FY25	4.1
Albany to Greenhithe subtransmission circuits breach SoSS	Albany to Greenhithe 110 kV to 33 kV subtransmission OH conversion	FY26	4.6
Albany subtransmission breaches SoSS	Albany GXP Rosedale Subtransmission Cable Reinforcement	FY28	5.0
Albany subtransmission breaches SoSS	Albany GXP Coatesville Subtransmission Cable Replacement	FY29	2.0
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	East Coast Road second 33/11 kV transformer & 33 kV cable	FY28	7.0
Forecast breach of SoSS on the subtransmission network under N and N-1 scenarios as well as constraints on the distribution network	Bush Rd ZSS 33/11 kV transformer upgrade T1+T2	FY34	0.5[1]

TABLE 10-13: ALBANY CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1]Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.6 WAIRAU PLANNING AREA

10.7.6.1 OVERVIEW

The Wairau Planning Area comprises the urban North Shore from Bayview and Milford, south to the Devonport peninsula and the Waitemata Harbour.

Important load centres include Takapuna (the North Shore CBD), the New Zealand Navy base in Devonport, the North Shore Hospital, and Auckland University of Technology Akaranga campus.

The zone substations in the Wairau Valley area have been targeted to supply the planned electrification of ferries.

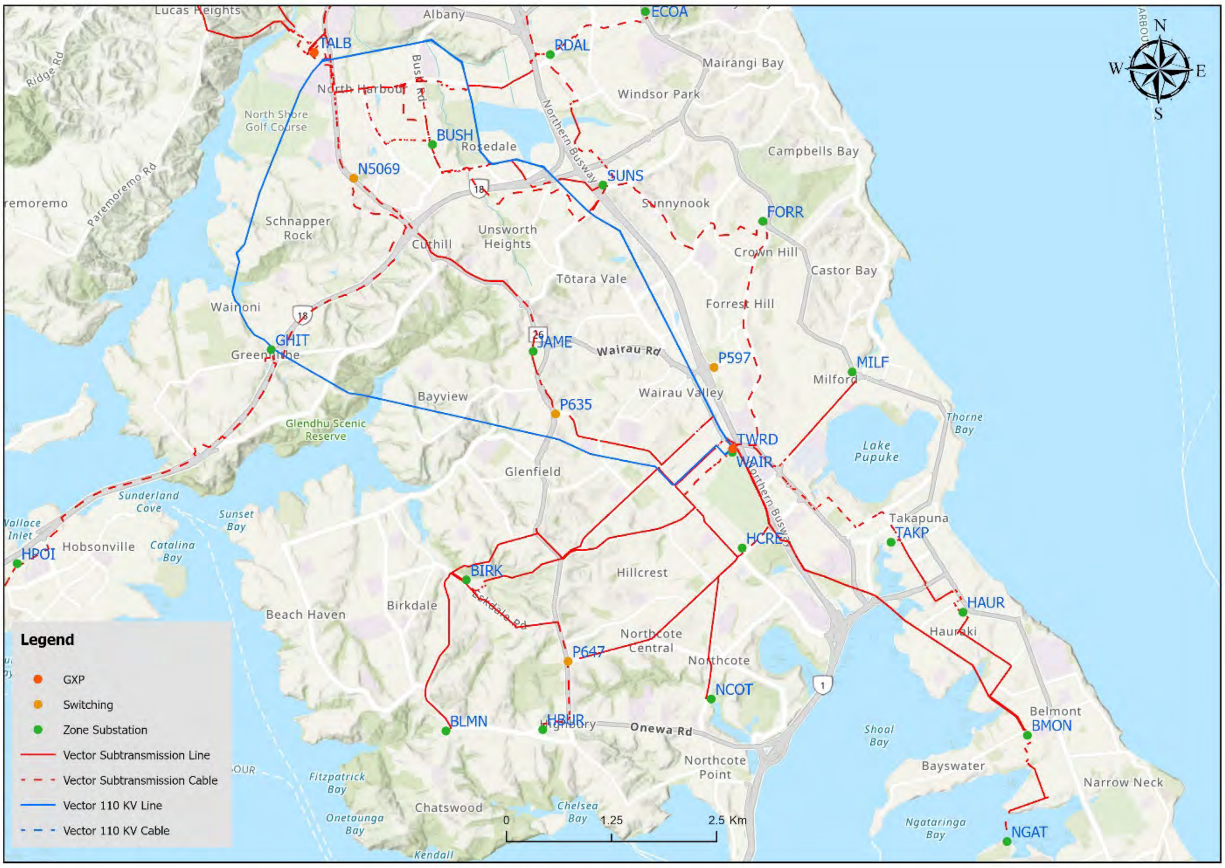


FIGURE 10.16: WAIRAU SUBTRANSMISSION NETWORK

10.7.6.2 SUBTRANSMISSION

The area is supplied from the Wairau GXP. The subtransmission network operates at 110 kV and 33 kV and consists of predominately overhead lines.

There are no constraints currently forecast to occur on the subtransmission network within the AMP forecast period, however a constraint appears just after the AMP period on the Wairau – Takapuna 33 kV circuit and remedial works will proceed in FY34.

10.7.6.3 ZONE SUBSTATION

Wairau GXP supplies 12 zone substations of which seven are single-transformer ZSSs, namely Highbury, Balmain, James St, Northcote, Milford, Hauraki, Ngataringa Bay and Takapuna and four are two-transformer ZSSs, namely Wairau Valley, Birkdale, Hillcrest, and Belmont.

As a result of E-Ferry and organic growth, Highbury zone substation is reaching capacity in 2026. This is also the cause of backstop shortfalls at other zone substations. A second transformer and accompanying sub-transmission circuit is planned in FY25 to alleviate these constraints.

Three issues have been identified at the Ngataringa Bay ZSS:

- The 33 kV oil-filled submarine cable to Ngataringa Bay ZSS is approaching the end of its serviceable life which presents a network security risk and also an environmental risk from oil leaks
- Ngataringa Bay ZZS has insufficient 11 kV backstop capacity for an outage at peak demand
- Ngataringa Bay ZSS is low-lying and close to the coast, making it vulnerable to flooding. The flooding risk is expected to increase under forecast climate change scenarios

The first two issues are addressed by the Ngataringa Bay 11 kV cable replacement project starting in FY24. The permanent solution is planned for FY25 and will involve installation of a third transformer at Belmont ZSS to supply the area via new cables and thereafter decommissioning and removal of Ngataringa Bay ZSS.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Balmain	RES	8.8	9.5	9.6	9.6	9.7	9.9	10.2	10.4	10.7	10.9	11.3
Winter	Belmont	RES	13.6	13.7	13.9	14.1	14.3	17.0	17.6	18.1	18.7	19.2	20.2
Winter	Birkdale	RES	22.3	22.4	22.4	22.5	22.6	23.1	23.6	24.1	24.7	25.2	26.2
Winter	Hauraki	RES	5.5	5.7	5.9	6.0	6.2	6.7	7.2	7.7	8.1	8.6	9.4
Winter	Highbury	COM	13.1	13.4	15.9	16.2	16.5	17.1	17.8	18.5	19.2	19.8	21.1
Winter	Hillcrest	RES	24.9	25.7	26.1	26.5	26.9	27.9	28.9	29.9	30.8	31.8	33.3
Winter	James Street	RES	18.8	18.9	19.0	19.1	19.2	19.9	20.6	21.2	21.9	22.5	23.7
Winter	Milford	RES	7.4	7.6	7.8	7.9	8.1	8.5	8.9	9.4	9.8	10.2	10.9
Winter	Ngataringa Bay	RES	7.8	7.8	7.9	9.6	9.7	9.9	10.2	10.4	10.7	10.9	11.4
Winter	Northcote	RES	6.0	6.1	6.2	6.3	6.4	6.6	8.6	8.9	9.1	9.4	9.8
Winter	Takapuna	COM	7.8	8.2	8.5	8.9	9.3	10.0	10.6	11.2	11.9	12.5	13.5
Winter	Wairau Road	COM	18.9	19.0	20.9	21.1	21.3	21.9	22.6	25.0	25.6	26.1	27.1

TABLE 10-14: WAIRAU LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.6.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV with a combination of overhead and underground circuits. In the urban and commercial areas, steady densification (taller buildings and higher density construction) is driving an increase in demand causing capacity constraints on the 11 kV feeders. To address this constraint, feeder upgrades are planned for Takapuna (Northcroft Street) and Hillcrest ZSS, along with a new feeder at Highbury.

10.7.6.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Belmont ZSS capacity	Belmont 33/11 kV T3	FY25	8.2
Highbury subtransmission capacity	Highbury 33/11 kV 2nd transformer and 2nd 33 kV cable	FY25	9.5
Ngataringa Bay flood risk; Ngataringa Bay security of supply	Ngataringa Bay Direct Supply Belmont ZSS	FY25	8.4[1]
Project co-ordinated with Transpower	Wairau 220/33 kV 2nd transformer T9 enabling works	FY25	0.8[1]
Feeder supply and backstop shortfall	Highbury 11 kV New Feeder	FY27	1.0
Northcroft feeder supply and backstop shortfall	Northcroft 11 kV reinforcement	FY28	1.9
Hillcrest feeder supply and backstop shortfall	Hillcrest K13 11 kV feeder reinforcement	FY30	0.4
Subtransmission load forecast breaches SoSS	Wairau-Takapuna 33 kV cable upgrade	FY34	0.5[2]

TABLE 10-15: WAIRAU CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

[2] Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.7 AUCKLAND CBD PLANNING AREA

10.7.7.1 OVERVIEW

The Auckland CBD covers the area bounded by the Northern Motorway (State Highway 1, SH1) towards the Harbour Bridge, the extension of (State Highway 16, SH16) down Grafton Gully and the Waterfront. The CBD network supplies over 37,000 customers (ICPs) with a total demand of 180 MVA.

There was an impact on the CBD demand due to the COVID-19 lockdowns. The demand declined significantly during each of the lockdown periods, and bounced back after lockdown ended, however, is still below the pre COVID level. While this trend could allude to some long-term changes that we will continue to monitor, it is also important to recognise the large-scale City Rail Link (CRL) project will improve transport access and could increase attractiveness of the CBD as a business, entertainment and residential area. This is supported by continuous connection and works requests in the CBD area throughout the COVID years. We will continue to closely monitor the demand forecast for the CBD to assess the COVID recovery as well as longer-term trends such as hybrid working.

The CBD is undergoing a transformation driven largely by the redevelopment of existing commercial sites, the City Rail Link (CRL) project and potentially the Light Rail Transit (LRT) project and Electric Ferry project at Downtown Ferry Terminal (DTFT).

Streetscape improvement projects (e.g. Quay St and associated wider Britomart area) provide the opportunity to future proof the network such as through installation of cables and ducts at a lower cost. These opportunities are assessed on a case by case basis.

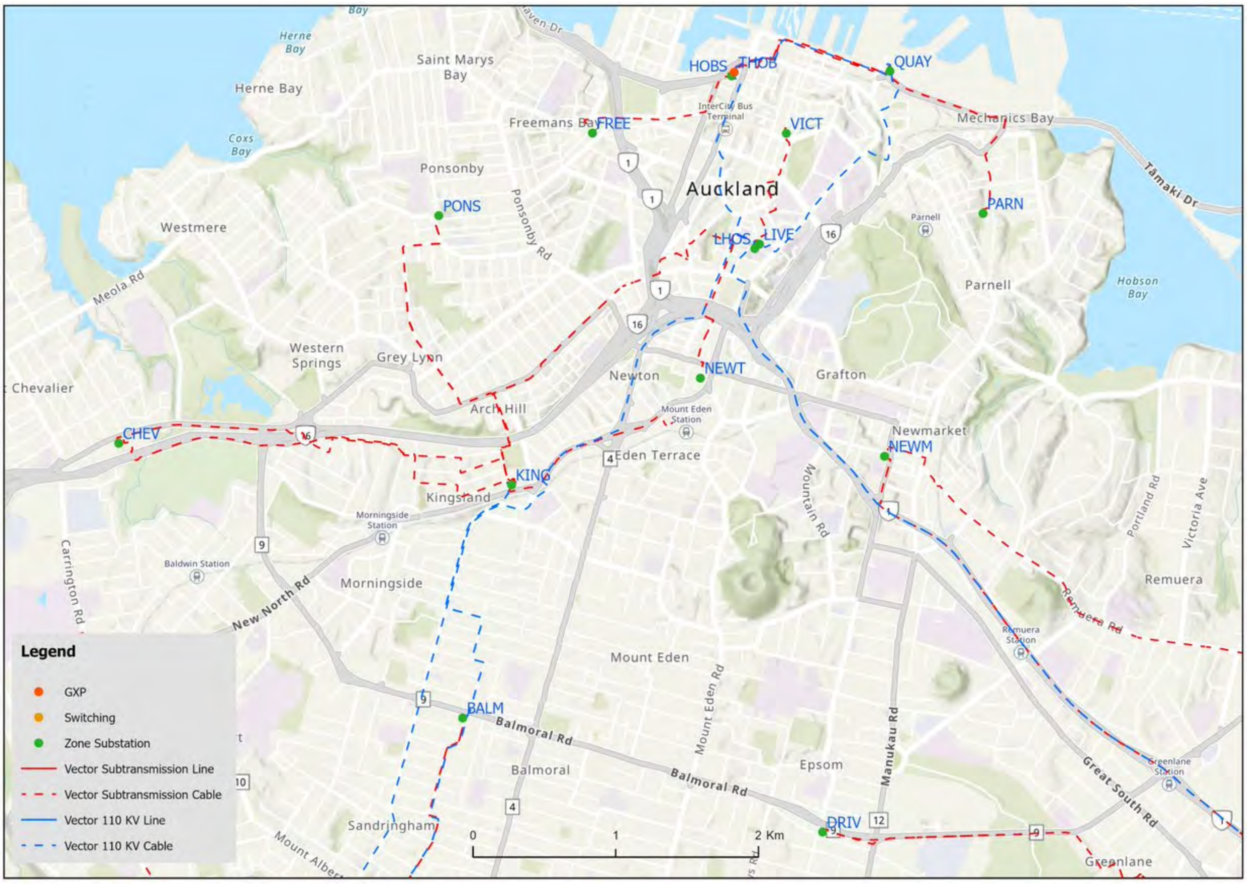


FIGURE 10.17: AUCKLAND CBD SUBTRANSMISSION NETWORK

10.7.7.2 SUBTRANSMISSION

The CBD area is supplied by subtransmission circuits at 110 kV and 22 kV. All subtransmisison circuits are underground cables to improve resilience of the network.

The 110 kV network is supplied by two independent 110 kV grid sources, with two feeders from Penrose GXP and one feeder from Hobson GXP. This provides network security at N-1 without an outage and N-2 with a short outage. An independent backup supply is available from Roskill GXP.

The 22 kV subtransmission network is installed between the three primary substations, namely Hobson ZSS, Liverpool ZSS and Quay ZSS to provide additional backup to the 110 kV supply. The 22 kV subtransmission network is then used to supply four other zone substations, namely Freemans Bay ZSS, Newton ZSS, Parnell ZSS and Victoria ZSS.

No constraints are identified to occur in the subtransmission network, during the AMP planning period.

10.7.7.3 ZONE SUBSTATION

The CBD area is served by three primary zone substations, namely Liverpool, Hobson and Quay. The substations are connected to the 110 kV network via a total of eight 110/22 kV transformers and the 22 kV buses are interconnected via 22 kV subtransmission circuits. Each of these three primary zone substations also has multiple 22/11 kV transformers to step the voltage down to distribution level and ensure security of supply.

The 22 kV subtransmission network supplies an additional four 22/11 kV zone substations, namely Freemans Bay ZSS, Newton ZSS, Parnell ZSS and Victoria ZSS.

Load forecast shows the security of supply standard is expected to be breached at Newton zone substation from 2031, resulting from the proposed developments in the Mt Eden precinct after completion of CRL works. Vector currently plans to establish a new zone substation at Mt Eden to resolve the constraint (refer to Roskill Planning Area for project details).

Security breaches are also forecast at Quay 11 kV and Victoria 11 kV around 2029 and 2031, respectively, due to the load growth in the existing 11 kV network. Vector's plan is to convert selected 11 kV distribution substations to 22 kV and transfer the load to the 22 kV distribution network. New load will be connected to the 22 kV network wherever feasible. This approach will avoid the costly upgrade at the two zone substations and is in line with the long-term plan to upgrade the CBD distribution network from 11 kV to 22 kV.

			LOAD FORECAST (MW)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Freemans Bay	COM	16.0	16.1	16.1	16.2	16.3	17.1	17.9	18.6	19.4	20.1	21.3
Summer	Hobson 110/11 kV	CBD	11.8	12.1	12.3	12.6	12.9	13.4	13.9	14.4	14.9	15.4	16.1
Winter	Hobson 22/11 kV	CBD	12.4	12.6	12.9	13.1	13.3	13.9	14.4	15.0	15.5	16.0	16.8
Winter	Hobson 22 kV	CBD	52.4	68.9	73.4	78.2	74.8	76.9	79.0	83.7	85.8	87.9	90.9
Winter	Liverpool 22 kV	CBD	82.1	97.7	101.1	104.6	106.0	111.5	115.6	123.1	127.2	131.3	137.2
Winter	Liverpool	CBD	25.3	33.2	33.8	34.3	34.9	36.3	37.6	39.0	40.3	41.7	43.5
Winter	Newton	COM	18.5	18.7	20.6	21.1	21.7	23.1	24.6	26.1	27.5	29.0	31.0
Winter	Parnell	COM	15.0	15.0	15.1	15.2	15.3	15.8	16.3	16.9	17.4	17.9	18.9
Winter	Quay 22 kV	CBD	46.9	47.1	47.2	47.4	65.6	74.0	77.5	78.9	80.3	81.8	84.3
Winter	Quay	CBD	18.9	18.9	19.0	19.1	19.2	19.9	22.8	23.5	24.3	25.0	26.3
Summer	Victoria	CBD	15.6	15.8	15.9	16.1	16.3	16.8	17.4	17.9	18.5	19.0	20.0

TABLE 10-16: CBD LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.7.4 DISTRIBUTION NETWORK

The distribution network in the CBD comprises both 11 kV and 22 kV feeders from the zone substations. The feeders are generally radial and interconnected via open points to meet Vector's security of supply standard.

The long-term plan for CBD distribution network is to progressively expand the 22 kV network coverage that will, over the long term, replace the aging 11 kV network, and increase capacity in the CBD. A key long-term plan is to provide 22 kV network coverage to ensure large new customer connections (typically for large new building developments) will be supplied from the new 22 kV distribution network. Conversion of existing 11 kV distribution load will also be carried out when existing 11 kV assets require replacement and when future constraints on the 11 kV network are forecast.

Auckland Transport is carrying out streetscape project in the Britomart area bounded by Quay St, Queen St, Customs St and Britomart Place, and additional new potential loads have been identified. As the roads are being renewed (dug up and reinstated) and existing cables relocated, there are synergies and opportunities to expand the 22 kV network coverage to future proof the network by installing 22 kV cables and ducts. If Vector does not take this opportunity, then it may be difficult to get access to excavate these roads within the time period required to meet the growing demand of the CBD.

10.7.7.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	CBD 22 kV Extension Airedale St	FY24	2.0[1]
	CBD Albert Wellesley St 22 kV extension	FY25	3.1[1]
	CBD Hobson St Bradnor11 kV Lane 22 kV extension	FY28	2.2
Risk of capacity and security breach resulted from aged 11 kV PILC cables	CBD 11 kV to 22 kV Conversion Hobson St	FY24	0.8
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	CBD Victoria St linear park 22 kV extension	FY24	0.8[1]
Enabling works in co-ordination with City Rail Link (CRL)	CRL C3 Aotea Station Works	FY24	0.3[1]
Risk of capacity and security breach resulted from aged 11 kV PILC cables	CBD 22 kV extension Emily Place	FY24	2.1
Risk of security breach resulted from inaccessible tunnel cables	Quay 11 kV reinforcement for feeders in tunnel	FY24	0.5
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	CBD Tyler St East 22 kV extension	FY25	1.0
Synergy opportunity to future proof for area in co-ordination with City Rail Link (CRL) project	K Rd CRL OSD future-proofing ducts and cables	FY25	3.9[1]
Synergy opportunity to future proof for CBD 22 kV distribution network to meet long term growth	CBD Wellesley St 22 kV extension bus improvement	FY25	0.8
Quay ZSS 11 kV breaches SoSS	CBD Quay 11 kV to 22 kV conversion for security	FY28	4.4
Hobson feeders J02 & J09 breaches SoSS	Hobson Waterfront 22 kV feeders new	FY29	5.0
Hobson feeders HBOS J38, LIVE J05 and LIVE J17 breach capacity and SoSS	Hobson new 22 kV feeder re-termination	FY32	0.6
CBD 11 kV network breaches SoSS	CBD 22 kV Network Rollout	FY33	26.5
Freemans Bay feeder K19 breaches SoSS	Freemans Bay 11 kV reinforcement	FY34	1.0[2]
Quay ZSS 22 kV breaches SoSS	Quay substation 22 kV upgrade	FY35	0.2[2]

TABLE 10-17: CBD CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

[2] Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.8 ROSKILL PLANNING AREA

10.7.8.1 OVERVIEW

The Roskill planning area is located to the west of Auckland CBD and extends from Mt Eden west to Avondale and north to St Marys Bay. In total, the GXP supplies about 68,800 customers (ICPs) with a total load of about 160 MVA.

Commercial multi-level buildings and multi-level high density residential load growth is expected around Mt Eden station. Significant housing intensification by Kainga Ora in wider Roskill area is underway and forecast to add 17,000 dwellings over the next 20 years.

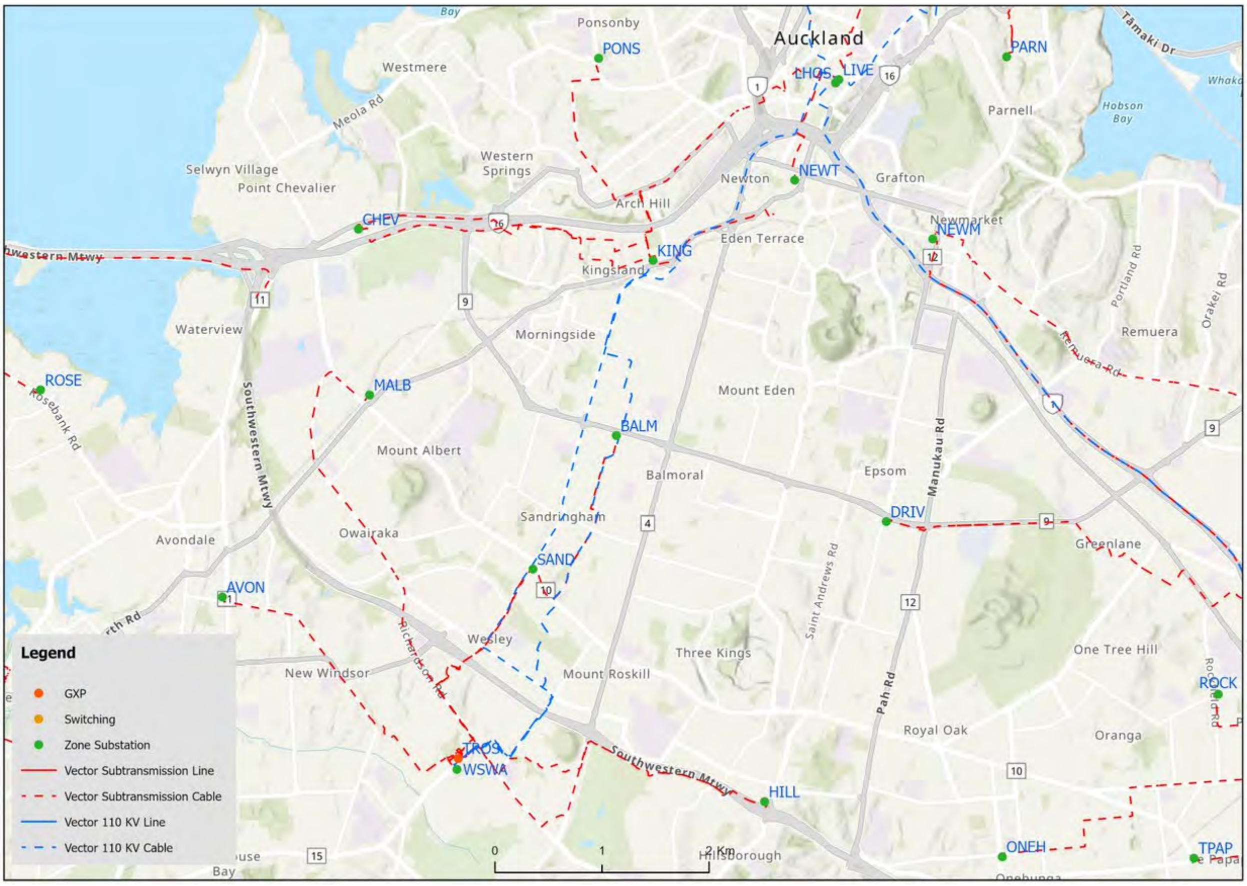


FIGURE 10.18: ROSKILL SUBTRANSMISSION NETWORK

10.7.8.2 SUBTRANSMISSION

Roskill GXP provides a 110 kV supply to Vector's Kingsland 110/22 kV substation and a separate 22 kV supply to six Vector substations. Kingsland 22 kV buses provide supply to three zone substations. Roskill GXP also provides backup to the CBD network via a single 110 kV circuit to Liverpool substation. Two 110 kV circuits are connected between Roskill 110 kV GXP and Kingsland 110/22 kV transformers.

A 22 kV circuit connecting between Kingsland 22 kV bus and Liverpool 22 kV bus is used for backup purposes.

The subtransmission circuits at Sandringham are expected to breach SoSS from 2030 and Chevalier from 2033. Mt Albert and White Swan are expected to breach both capacity and security from 2033.

At Kingsland 110/22 kV substation, the existing two 110 kV circuits and the backup 22 kV circuit from Liverpool are all fluid filled cables over 50 years old. It makes the substation vulnerable upon any fluid filled cable failure. A project is proposed to connect the substation to the 110 kV circuit between Roskill and Liverpool utilising the capacity available. Feasibility will be investigated, and decision made in due course.

10.7.8.3 ZONE SUBSTATION

There are nine zone substations supplied from Roskill GXP, three via Kingsland zone substation using 22 kV subtransmission, two via Sandringham 22 kV buses, and the remaining four directly from Roskill 22 kV buses.

Mt Albert substation is currently supplied from Roskill 22 kV GXP via a single subtransmission circuit and single transformer. Due to the age and condition, the transformer is under replacement in 2023, and the subtransmission circuit planned in 2030, both under asset replacement projects. The replacement projects will improve the capacity and security at Mt Albert substation until 2033 when it is expected to breach the SoSS. Vector has identified the preferred solution to resolve the constraint is to install a second subtransmission circuit and second transformer. The supply will be transferred to Sandringham 22 kV buses, instead of Roskill 22 kV GXP, to take advantage of shorter cabling distance and existing spare circuit breakers, thus lower cost. This replacement project will be implemented based on the ultimate substation configuration. The augmentation project is planned for completion by 2032.

The proposed commercial and housing development at Mt Eden precinct by City Rail Link is expected to add significant load in the area. Capacity and security constraints are identified at Newton substation (included in CBD Planning Area), Kingsland substation, and various 11 kV feeders from 2031. It is proposed to establish a new zone substation at Mt Eden area to resolve the constraints. Land needs to be purchased in FY26, during design stage of the development, to secure an optimal location.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Avondale	RES	27.3	27.9	26.3	26.7	26.0	24.7	25.1	25.6	26.1	26.6	27.4
Winter	Balmoral	RES	14.6	14.6	14.5	14.4	14.3	14.8	15.2	17.1	17.5	18.0	18.8
Winter	Chevalier	RES	20.5	20.5	20.5	20.4	20.5	21.2	22.0	22.7	23.4	24.2	25.4
Winter	Hillsborough	RES	16.2	16.1	16.0	19.4	19.4	17.3	17.9	18.5	19.0	19.5	20.2
Winter	Kingsland 22 kV	RES	55.7	55.4	55.3	55.2	55.1	57.2	59.2	61.2	63.3	65.3	68.9
Winter	Kingsland	RES	22.7	22.5	22.6	22.6	22.7	23.7	24.8	25.9	27.0	28.1	29.9
Winter	Mt Albert	RES	7.2	7.4	7.6	7.8	8.5	9.5	10.1	10.6	11.2	11.7	12.4
Winter	Ponsonby	RES	14.8	14.7	14.6	14.4	14.3	14.7	15.1	15.5	15.9	16.3	17.2
Winter	Sandringham 22 kV	RES	34.0	34.4	34.0	33.6	33.2	35.6	38.6	44.5	47.7	50.3	54.5
Winter	Sandringham	RES	20.1	20.7	20.4	20.0	19.7	21.7	24.3	28.5	31.3	33.5	37.0
Winter	White Swan	IND	32.9	32.9	28.8	31.6	31.3	33.6	34.1	34.6	34.9	35.4	36.2

TABLE 10-18: ROSKILL LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.8.4 DISTRIBUTION NETWORK

The distribution network in the area comprises 11 kV feeders from the zone substations. The feeders are mainly radial and interconnected with open points in between to meet Vector's N-1 security of supply standard.

Two 11 kV feeder from Sandringham ZSS are expected to breach security in 2029, 2030 and 2032. It is proposed to install four new 11 kV feeders from Sandringham substation connecting to the existing network and rearrange the feeders in the area to remove the constraint.

10.7.8.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Newton substation, Kingsland substation, and various 11 kV feeders in the area breach capacity and security standard from 2031.	Mt Eden land purchase for ZSS	FY26	Not discl.
Synergy opportunity to future proof for Mt Eden precinct development in coordination with City Rail Link project	Mt Eden Precinct futureproof ducts and cables	FY26	3.2[1]
Synergy opportunity to future proof for Wairaka precinct development in coordination with Auckland Transport's road improvement project	Carrington Rd future-proofing ducts	FY27	5.0
Sandringham feeder K18 and Avondale K06 breaches SoSS	Sandringham Stoddard Rd 11 kV feeders new (KO driven)	FY29	4.4
Sandringham ZSS breaches SoSS	Sandringham subtransmission upgrade	FY29	6.8
Kingsland ZSS 22 kV supply at risk upon outage in both 110 kV fluid filled cables	Kingsland substation 110/22 kV reinforcement	FY31	17.8
Newton substation, Kingsland substation, and various 11 kV feeders in the area breach capacity and security standard from 2031	Mt Eden Zone Substation New	FY31	24.0
Chevalier capacity shortfall	Chevalier subtransmission upgrade	FY32	5.0
Mt Albert substation and Sandringham substation breach capacity and security standard from 2032 and 2035, respectively	Mt Albert Zone Substation capacity upgrade	FY32	24.0
Synergy opportunity to future proof for Mt Roskill housing development in coordinated with multiple third parties' projects	Mt Roskill Precinct futureproof ducts and cables	FY32	3.6
Sandringham feeder K14 breaches SoSS	Sandringham new 11 kV feeders to Mt Albert Rd east (KO driven)	FY32	1.6
White Swan ZSS breaches SoSS	White Swan substation capacity upgrade	FY32	7.9
Mt Albert feeder K16 breaches SoSS	Mt Albert new 11 kV feeders for capacity and security in MALB K16 (Wairaka housing)	FY33	4.0
Sandringham ZSS capacity and security shortfall	Sandringham third transformer	FY33	2.8

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $
Sandringham feeder K11 and K08 breaches SoSS	Sandringham Mt Albert Rd west 11 kV feeders new (KO driven)	FY33	2.0
Kingsland feeder K20 breaches SoSS	Kingsland new 11 kV feeder for capacity and security in KING K20	FY34	2.0[2]
White Swan feeder K16 and K20 breaches SoSS	White Swan new 11 kV feeders to Richardson Rd (KO driven)	FY34	0.4[2]

TABLE 10-19: ROSKILL CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

[2] Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.9 PENROSE PLANNING AREA

10.7.9.1 OVERVIEW

This is Vector's largest planning area from Mt Eden east to the Tamaki River. The area has over 84,700customers (ICPs) with a total demand of 302 MVA. The area is supplied by Transpower's Penrose GXP at 33 kV and 22 kV.

The planning area is well developed with limited greenfield development areas. The growth is mainly driven by redevelopment and densification of existing areas. The major housing redevelopment is Kainga Ora's Tāmaki regeneration project in Glen Innes, Panmure and Point England. The housing growth based on the latest medium forecast is an additional 13,000 dwellings (hence ICPs) by 2036, and 18,600 dwellings (hence ICPs) by 2046.

Ongoing commercial redevelopment is expected to continue in Newmarket and Sylvia Park precincts.

The load forecast at Penrose 33 kV is expected to breach security limits in the 2040s. It is the largest GXP in our network and supply diversification would increase security of supply by reducing common mode failure. A new GXP is proposed to be established at Southdown. Then, existing ZSS in the area (including Onehunga, Westfield, Te Papapa and Carbine) will be supplied from the new GXP when the subtransmission cables at the ZSS are due for replacement.

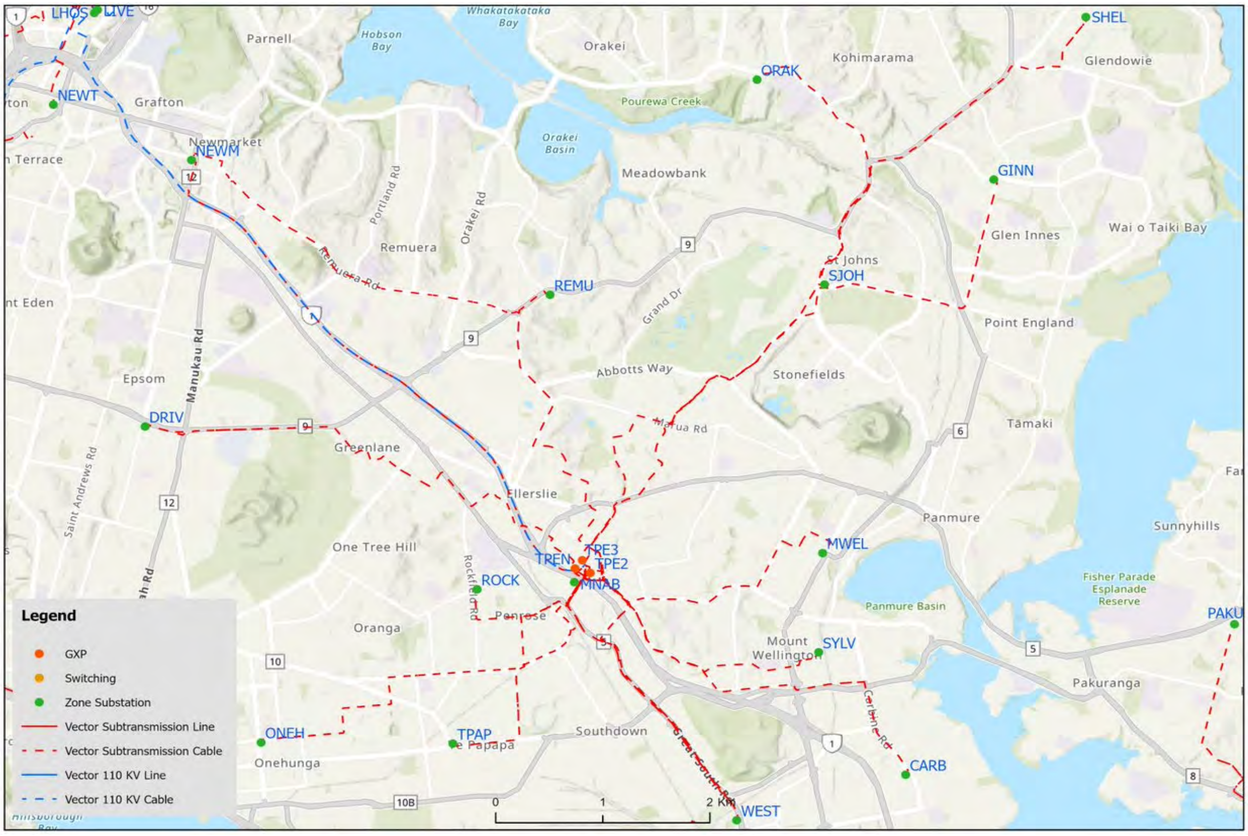


FIGURE 10.19: PENROSE SUBTRANSMISSION NETWORK

10.7.9.2 SUBTRANSMISSION

The subtransmission network in the area is comprised of 33 kV and 22 kV circuits connected between Penrose GXP and Vector's zone substations.

Based on modelling result, St Johns 33 kV circuits are expected to breach SoSS from 2032

10.7.9.3 ZONE SUBSTATION

There are 15 zone substations supplied from Penrose GXP. 10 are supplied directly from Penrose GXP at 33 kV, 3 are supplied via the switching station at St Johns substation, and 2 are supplied directly from Penrose at 22 kV. The Glenn Innes zone substation also includes a 1 MW / 2.3 MWh BESS installed in 2017.

The Newmarket ZSS is forecast to breach the SoSS from 2031 due to commercial redevelopment. Vector's preferred solution is to establish a new zone substation on the same site utilising the spare space available.

St Johns ZSS (11 kV) is expected to breach the SoSS at some stage in the long term due to the significant housing development by Kainga Ora's Tamaki Regeneration project. The long-term strategy is to establish a new substation to supply the area. Although the substation is not required to be constructed within this planning period, Vector will purchase land to secure an optimal site at design stage of the Kainga Ora development.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	Carbine	IND	14.4	14.3	14.3	14.3	14.3	14.4	14.6	14.7	14.9	15.0	15.3
Winter	Drive	RES	24.2	24.6	24.9	24.7	24.4	25.8	26.3	26.9	27.4	27.9	29.0
Winter	Glen Innes	RES	11.0	11.1	11.3	13.5	14.2	15.2	16.4	17.4	18.3	19.0	20.0
Winter	McNab	IND	39.1	50.7	50.5	50.4	50.3	51.1	51.8	52.6	53.3	54.1	56.1
Winter	Mt Wellington	IND	16.2	16.4	16.7	15.2	13.0	14.2	15.5	16.7	17.8	18.9	20.4
Summer	Newmarket	COM	38.2	38.8	31.8	32.2	32.7	34.2	35.8	37.3	38.8	40.3	42.7
Winter	Onehunga	IND	17.5	17.3	17.9	17.7	17.6	18.3	19.0	22.1	22.7	23.3	24.4
Winter	Orakei	RES	22.7	22.5	22.2	22.0	21.8	22.2	22.6	23.0	23.4	23.8	24.5
Winter	Remuera	COM	26.2	25.8	25.5	25.1	24.8	25.2	25.7	26.2	26.6	27.1	28.2
Winter	Rockfield	RES	23.7	23.4	23.2	22.9	22.7	23.1	23.6	24.0	24.5	24.9	25.8
Winter	St Johns 33 kV	RES	59.9	59.2	58.5	58.0	60.3	61.7	63.4	65.1	66.5	67.9	70.5
Winter	St Johns	RES	20.5	20.3	20.2	20.3	23.4	24.2	25.2	26.4	27.2	28.0	29.4
Summer	Sylvia Park	COM	17.0	17.0	17.1	17.1	17.2	17.4	17.6	17.9	18.1	18.3	18.7
Winter	St Heliers	RES	19.9	19.6	19.2	18.8	18.4	18.7	19.0	19.2	19.5	19.8	20.4
Winter	Te Papapa	IND	20.9	21.1	21.3	21.4	21.6	22.1	22.7	23.2	23.7	24.3	25.6
Winter	Westfield	IND	29.0	30.7	30.7	30.7	30.7	31.2	31.8	32.3	32.8	33.4	34.6

TABLE 10-20: PENROSE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS) DISTRIBUTION

10.7.9.4 DISTRIBUTION NETWORK

The distribution network in the area comprises 11 kV feeders from the zone substations. The feeders are mainly radial and interconnected with open points in between to meet Vector's N-1 security of supply standard.

A number of 11 kV feeders from Glen Innes, Mt Wellington, and St Johns ZSS's are expected to breach security between 2029 and 2032 as a result of load growth from Kainga Ora's housing development in the area. It is proposed to install new 11 kV feeders from Glen Innes and St Johns ZSS's connecting to the existing network and rearrange the feeders in the area to remove the constraint.

A number of 11 kV feeders from McNab, Onehunga, Rockfield, Te Papapa, and Westfield ZSS's are expected to breach security between 2029 and 2034 as a result of industrial / commercial load growth in the area. It is proposed to install new feeders from the ZSS's connecting to the existing network and rearrange the feeders in the area to remove the constraint.

In the longer term, a new Vector zone substation will be established at Southdown to off-load the large number of existing 11 kV feeders that are expected to breach SoSS, as well the ZSS in the area. It is proposed to purchase a land at Southdown for the new ZSS in FY24 , however, the construction of the new substation is beyond the 10-year window covered by the AMP.

10.7.9.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
McNab ZSS breaches SoSS	Ellerslie substation new	FY35	0.2[2]
Required for Tamaki new substation connection	Glen Innes 33 kV SWBD New	FY31	4.2
McNab feeder K08 breaches SoSS	McNab new 11 kV feeders to off load MNAB K08 and K03	FY33	4.0
Newmarket ZSS breaches SoSS	Newmarket substation capacity upgrade	FY31	21.5
Onehunga feeder K01 breaches SoSS	Onehunga 11 kV reinforcement for SoSS in ONEH K01	FY33	4.0
Onehunga feeder K02 breaches SoSS	Onehunga 11 kV reinforcement for SoSS in ONEH K02	FY29	4.0
Constraints on the 11 kV distribution network in the Southdown area	Southdown land purchase for ZSS	FY24	Not discl.
Glen Innes K06 and K09 breaches SoSS	St Johns Apirana Ave 11 kV feeders new (KO driven)	FY32	5.0
St John feeder K01 and Mt Wellington K14 breaches SoSS	St Johns new 11 kV feeders to Morrin Rd (KO driven)	FY33	3.6
St Johns feeder K02 and Mt Wellingtons K03 and K12, breach SoSS	St Johns Pilkington Rd 11 kV feeders new (KO driven)	FY29	7.0
Project coordinated with third parties' roadworks	Tamaki future-proofing ducts and cables	FY32	3.6
St Johns subtransmission and ZSS breaches SoSS	Tamaki Zone Substation New	FY31	24.0
Synergy opportunity to future proof for Kainga Ora's housing development in coordination with third parties' projects	Tamaki FP Merton Rd and Apirana Av	FY26	9.6
St Johns substation (11 kV) breaches capacity and security in long term. It is proposed to establish a new zone substation to remove the constraints. Land needs to be purchased to secure an optimal site at design stage of the development.	Land purchase and designation for Tamaki new substation	FY26	Not discl.
Te Papapa feeders K12 and K17 breaches SoSS	Te Papapa 11 kV reinforcement for security in TPAP K12 and K17	FY32	3.5
Rockfield feeder K10 capacity shortfall	Te Papapa new 11 kV feeders to off load ROCK K10	FY33	4.0
Westfield ZSS 11 kV breaches SoSS	Westfield 3rd transformer	FY34	1.0[2]
Westfield feeder K12 capacity shortfall	Westfield new 11 kV feeders for capacity in WEST K12	FY33	4.0

TABLE 10-21: PENROSE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

[2] Only the cost falling within this AMP period is shown, the project will proceed past this period.

10.7.10 PAKURANGA PLANNING AREA

10.7.10.1 OVERVIEW

The Pakuranga planning area covers most of the eastern Auckland suburbs, including East Tamaki, Flatbush, Pakuranga, Botany, Howick and all the way out to Bucklands Beach. The areas to the south of Flat Bush are designated greenfield growth areas and an additional 6 MVA increase in demand is expected by 2033.

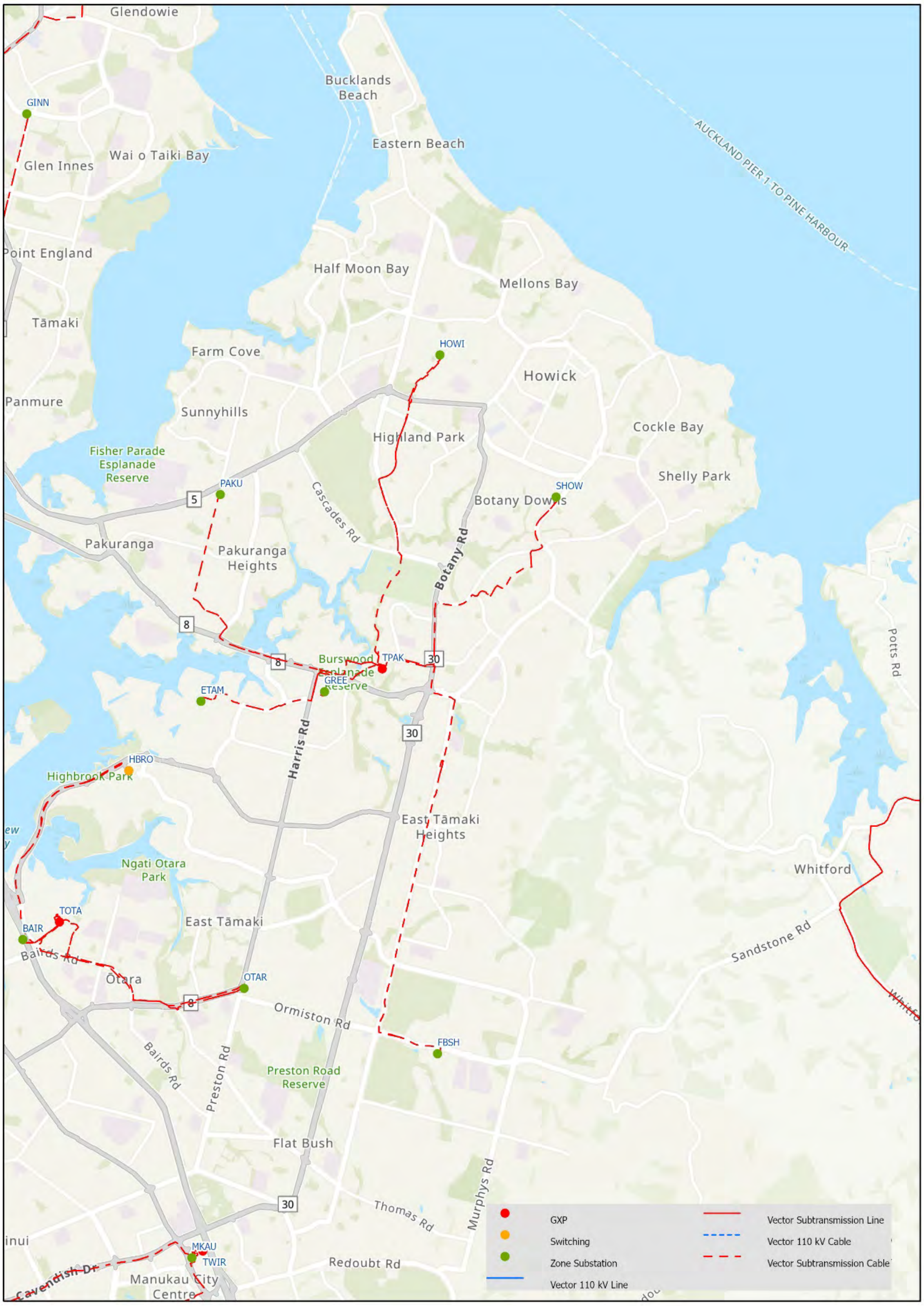


FIGURE 10.20: PAKURANGA SUBTRANSMISSION NETWORK

10.7.10.2 SUBTRANSMISSION

The area is supplied from the Pakuranga GXP. The subtransmission network operates at 33 kV and consists of underground cables that are installed along road reserves and supply six zone substations radially.

There are no subtransmission security constraints identified to occur during the AMP period.

10.7.10.3 ZONE SUBSTATION

Pakuranga GXP supplies six ZSS, all of which are comprised of multiple 33/11 kV transformers providing N-1 security of supply. Flatbush ZSS, East Tamaki ZSS, South Howick ZSS and Pakuranga ZSS each have two transformers while Howick ZSS and Greenmount ZSS both have three transformers.

There are no zone substation security constraints identified to occur during the AMP period.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	East Tamaki	COM	14.3	21.9	21.9	21.9	21.9	29.2	29.3	29.4	29.5	29.7	30.0
Winter	Flatbush	RES	23.0	23.5	24.1	24.6	25.2	26.1	27.0	27.8	28.7	29.6	31.1
Winter	Greenmount	COM	39.2	39.5	40.6	42.6	44.7	47.8	52.3	57.0	58.2	59.5	61.8
Winter	Howick	RES	38.6	41.7	41.9	42.1	42.3	43.3	44.4	45.4	46.4	47.4	49.3
Winter	Pakuranga	RES	20.7	20.8	20.9	21.0	21.1	21.7	22.4	23.0	23.6	24.2	25.3
Winter	South Howick	RES	21.7	21.9	22.0	22.2	22.4	23.2	24.1	24.9	25.7	26.6	28.1

TABLE 10-22: PAKURANGA LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.10.4 DISTRIBUTION NETWORK

The existing 11 kV feeder distribution is meshed and has sufficient backstopping capacity to feed adjacent ZSS.

As a result of an E-Ferry and organic growth in the Bucklands Beach area, a new feeder will be added to relieve local constraints and continue to meet the Security of Supply Standard.

New road development projects being implemented by the Council within the Flat bush area provide opportunities for Vector to install cable ducts at lower cost to provide future options for network development. The decision to install ducts is assessed on a case by case basis.

The available capacity of the existing backstop supply is forecast to decrease towards the end of the AMP period for a Greenmount distribution feeder. A distribution switch will be installed to connect to an adjacent feeder to enable an alternative point of supply under a contingency and maintain the required level of backstop capacity available.

10.7.10.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Howick K13 feeder capacity shortfall	Howick Bucklands Beach 11 kV feeder new	FY28	2.8
SOSS backstop constraint. GREE K16 (Harris Road south) summer backstop shortfall requires RMU install.	Greenmount-Harris Road 11 kV feeder capacity optimisation - RMU installation	FY32	0.4
Flat Bush future proofing	Flatbush Link Road future proofing distribution cable ducts	FY26	0.5

TABLE 10-23: PAKURANGA CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.11 MANGERE PLANNING AREA

10.7.11.1 OVERVIEW

The Mangere Planning Area covers the Mangere township and surrounding residential, commercial and industrial areas, extending south to the areas identified for future greenfield development surrounding the Auckland airport.

There is significant demand growth forecast due to an additional 10,000 dwellings that are planned by Kainga Ora over the next 15 years. These will be located between the Mangere Central area northwards towards Mangere Bridge and eastwards towards Middlemore. The growth will be driven by housing redevelopment and densification of existing areas.

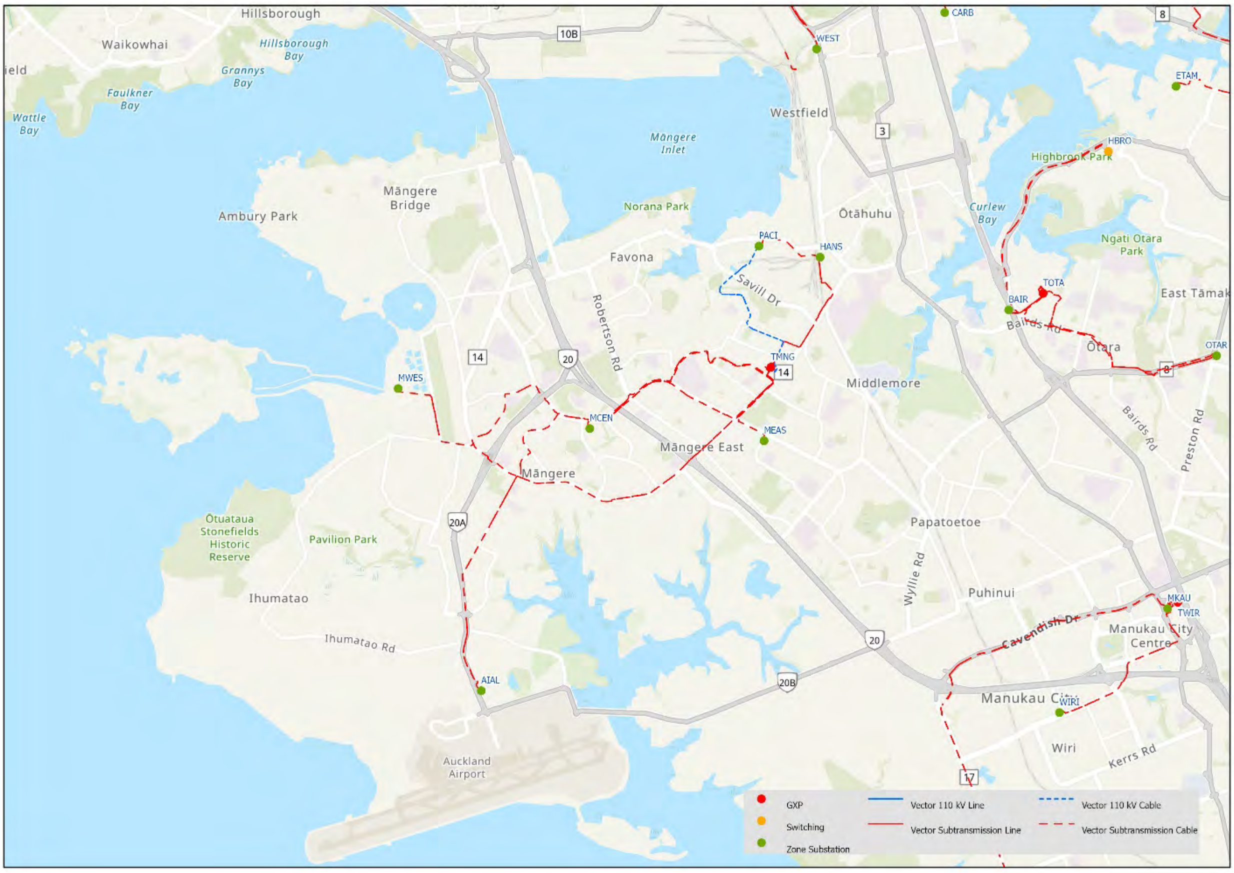


FIGURE 10.21: MANGERE SUBTRANSMISSION NETWORK

10.7.11.2 SUBTRANSMISSION

The area is supplied from the Mangere GXP. The subtransmission network operates at 110 kV and 33 kV and consists of predominately radial underground cables. The two 110 kV feeders supply 110/33 kV transformers at Pacific Steel and five 33 kV feeders supply four 33/11 kV zone substations.

There are no subtransmission security constraints identified to occur during the AMP period.

10.7.11.3 ZONE SUBSTATION

Mangere GXP supplies four zone substations, all with multiple 33/11 kV transformers which provide security of supply.

There is a demand constraint identified at Mangere Central during the AMP period, due to the significant residential and commercial growth in the area. Vector will purchase land in FY24 for a future zone substation (to be called Mangere South and expected to be commissioned in FY29) to ensure we are able to secure land in an optimal location.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Hans	COM	23.7	25.1	26.5	26.8	27.1	28.2	29.4	30.4	31.5	32.5	34.3
Summer	Mangere Central	RES	29.7	30.0	30.0	30.2	30.6	32.4	33.3	34.3	35.4	36.7	38.5
Winter	Mangere East	RES	28.1	28.5	29.7	31.0	32.0	33.2	34.6	36.2	37.5	38.8	40.6
Winter	Mangere West	COM	20.9	21.0	25.3	25.6	28.6	29.1	29.6	30.1	30.4	30.7	31.2

TABLE 10-24: MANGERE LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.11.4 DISTRIBUTION NETWORK

The distribution network operates at 11 kV, being overhead in the rural areas and underground in the urban areas. The forecast load growth in the Mangere area is expected to cause a number of constraints which will be addressed through a number of new feeders from Mangere Central (Robertson Rd, Massey Rd, Idlewild Ave and Favona) and Hans (Middlemore Cres) ZSS.

10.7.11.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Mangere Central ZSS - SoSS breach in FY30 and distribution feeder capacity constraints to supply Airport Park industrial development area beyond 2030	Mangere South secure site for new zone substation	FY24	1.2
Mangere East feeder K16 backstop and capacity shortfall	Mangere Central Robertson Rd 11 kV feeder new	FY27	2.3
Hans feeder K20 backstop shortfall	Hans Middlemore Cres 11 kV feeder new	FY29	3.3
Mangere Central ZSS - SoSS breach in FY30 and distribution feeder capacity constraints to supply Airport Park industrial development area beyond 2030	Mangere South new zone substation	FY29	18.2
Mangere Central feeder K17 backstop and capacity shortfall	Mangere Central Idlewild Ave 11 kV feeder new	FY30	2.0
Mangere Central feeder K11 backstop shortfall	Mangere Central Favona 11 kV feeder new	FY30	1.3
Mangere East feeder K11 backstop and capacity shortfall	Mangere Central Massey Rd 11 kV feeder new	FY33	1.7

TABLE 10-25: MANGERE CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.12 TAKANINI PLANNING AREA

10.7.12.1 OVERVIEW

The Takanini Planning Area covers the urban areas of Manurewa, Takanini and Papakura townships, extending east to the more remote areas of Clevedon, Maraetai, Beachlands and Waiheke Island. A MW-scale generation facility from landfill is operating in the area.

Waiheke Island is supplied by two 33 kV subtransmission cables from Maraetai. The feeders start off as overhead lines and then switch to submarine cabling to cross the Tamaki Strait, and then convert to underground cabling upon reaching the island. There is a steady demand growth forecast over the next 10 years, with a total demand increase of 7 MVA.

The Takanini area, excluding Waiheke Island, is driven predominantly by residential growth along with large commercial customers, E-Bus and E-Ferry.

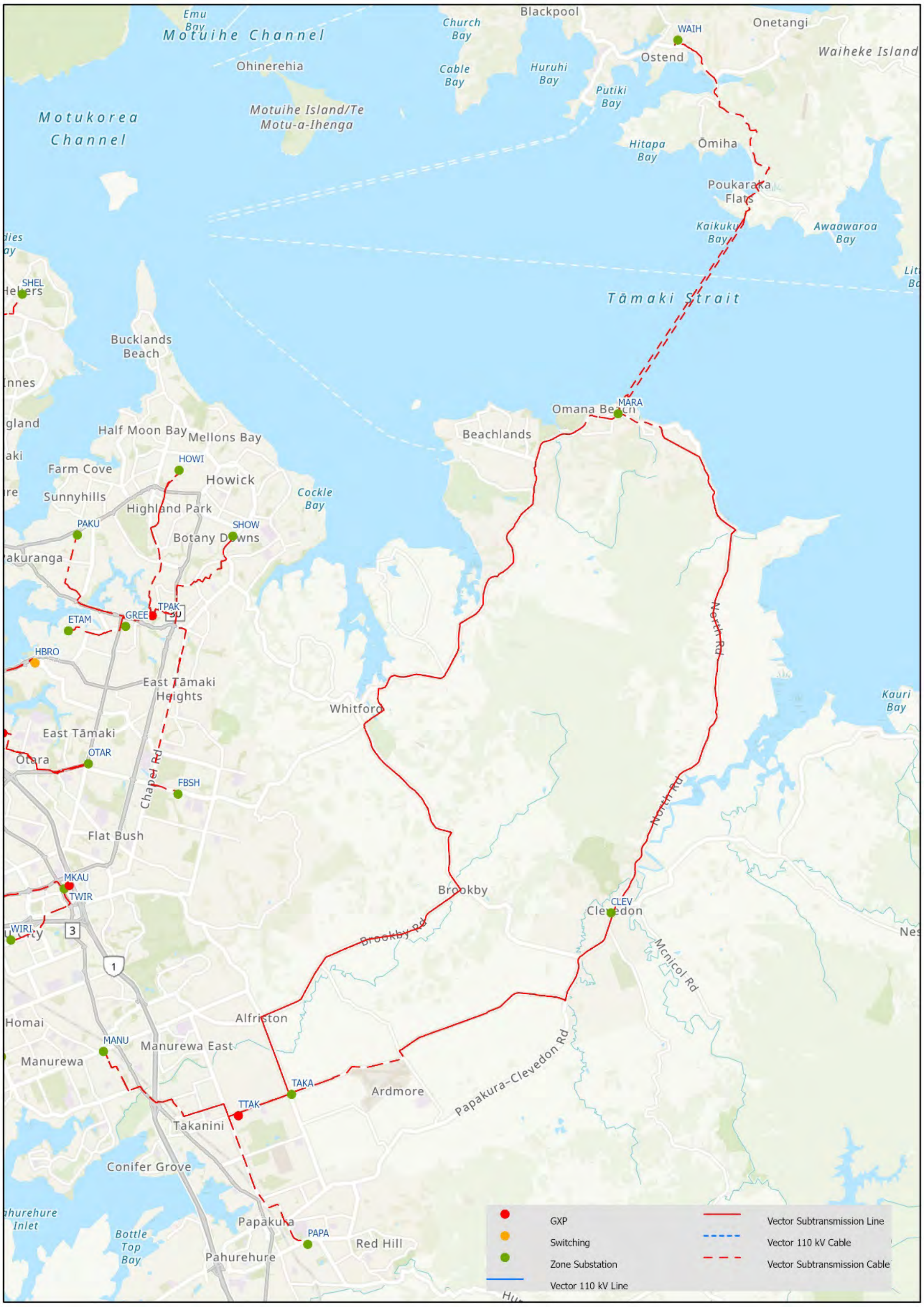


FIGURE 10.22: TAKANINI SUBTRANSMISSION NETWORK

10.7.12.2 SUBTRANSMISSION

The area is supplied from the Takanini GXP. The subtransmission network operates at 33 kV and consists of predominately long radial overhead lines and two cables with submarine sections supplying Waiheke Island. The network also consists of underground 33 kV cables to supply Manurewa, Takanini and Papakura.

The subtransmission cables to Waiheke Island provide N-1 security, but any damage to the undersea portion of these circuits takes considerable time to repair, leaving the supply to the island dependent on a single circuit and without any backup at distribution level or any significant embedded generation. These cables are located adjacent to each other and do not have mechanical protection. Recent anchor strikes have identified that the risk of outages is higher than thought and needs to be mitigated. To mitigate the risk and ensure compliance with the SoSS, Vector will install a third subtransmission cable. The new cable will be spatially separated from the existing cables and include mechanical protection to improve resilience to anchor strikes.

As a result of rapid organic growth, large commercial developments, and an E-ferry terminal, additional sub-transmission capacity is required in both the Manurewa and Maraetai areas to adhere to the SoSS.

10.7.12.3 ZONE SUBSTATION

Takanini GXP supplies six zone substations of which five have multiple 33/11 kV transformers and one, namely Clevedon ZSS, consists of a single 5 MVA 33/11 kV transformer. Waiheke Island ZSS consists of two transformers, each sized to be able to supply the entire island load, hence providing N-1 redundancy.

Takanini ZSS breaches the SoSS as 2027 approaches. A third transformer and accompanying sub-transmission cable in FY26 will add capacity to the zone substation and allow for future commercial and residential developments in the area.

As a result of organic growth in addition to high commercial interest, a new Takanini South ZSS is expected to be required in the long term (e.g. beyond AMP period). Provision to acquire land has been added to this AMP cycle.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Clevedon	RES	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.2
Winter	Manurewa	RES	48.5	55.8	58.4	58.8	59.1	60.5	61.9	63.3	64.7	66.1	68.6
Winter	Maraetai	RES	10.2	10.3	11.3	12.3	15.3	16.6	17.9	19.2	20.5	21.9	22.9
Winter	Papakura	RES	28.7	29.2	29.7	30.2	30.7	32.0	33.3	34.6	35.9	37.3	39.5
Winter	Takanini	COM	24.7	28.8	31.3	31.9	36.7	37.8	38.8	39.9	40.9	41.8	43.3
Winter	Waiheke	COM	12.6	12.8	13.1	13.4	13.6	14.4	15.3	16.1	16.9	17.8	18.9

TABLE 10-26: TAKANINI LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.12.4 DISTRIBUTION NETWORK

The distribution network in this planning area covers a very large rural area from Clevedon south to Kawakawa Bay and the eastern side of Waiheke Island. It operates at 11 kV and consists of predominately overhead lines. In Kawakawa Bay, a 1 MW / 1.7 MWh BESS to provide additional resilience for the network and local wastewater treatment facility has been installed in 2020.

Vector forecasts that some of the Clevedon ZSS feeders will have a combined shortfall of less than 800 kVA by the end of the AMP period, which is still compliant with the SoSS (Clause 5). Vector will continue to monitor the load growth and shortfall and will take appropriate actions when required.

Significant growth caused by a mix of residential and commercial development has triggered the need for new feeders and reinforcements in Manurewa, Papakura and Takanini between FY26 and FY32

10.7.12.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Network Supply Point (NSP) for regulatory compliance	Kawakawa NSP metering installation	FY24	0.8
Maraetai subtransmission breaches SoSS	Maraetai Subtransmission Reinforcement	FY26	9.5
TAKA ZSS breaches SoSS	Takanini zone substation capacity upgrade	FY26	11.6
Waiheke island subtransmission supply resilience	Third subtransmission submarine cable	FY26	7.5
Takanini feeder K09 breaches SoSS	Takanini K09 11 kV feeder reinforcement	FY28	0.4
Manurewa feeder K12, K07 & K11 capacity shortfall	Manurewa Alfriston Rd 11 kV feeder new	FY28	2.3
Papakura feeder K02 breaches SoSS	Papakura Settlement Rd 11 kV feeder new	FY31	1.9

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Papakura feeder K10 breaches SoSS	Takanini Walters Road 11 kV feeder new	FY32	4.0
Constraints on the 11 kV distribution network in the Takanini area	Takanini South land purchase for ZSS	FY29	Not discl.
Manurewa subtransmission breaches SoSS	Manurewa Subtransmission reinforcement	FY32	2.0

TABLE 10-27: TAKANINI CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.13 OTAHUHU PLANNING AREA

10.7.13.1 OVERVIEW

Otahuhu Planning area is one the smallest non-CBD planning areas. It consists of Highbrook, Bairds and Otara. A total demand growth of 25 MVA is forecast by the end of the AMP period. The areas growth is due to intensification of industrial development around Otahuhu GXP and deployment of EV Bus chargers.

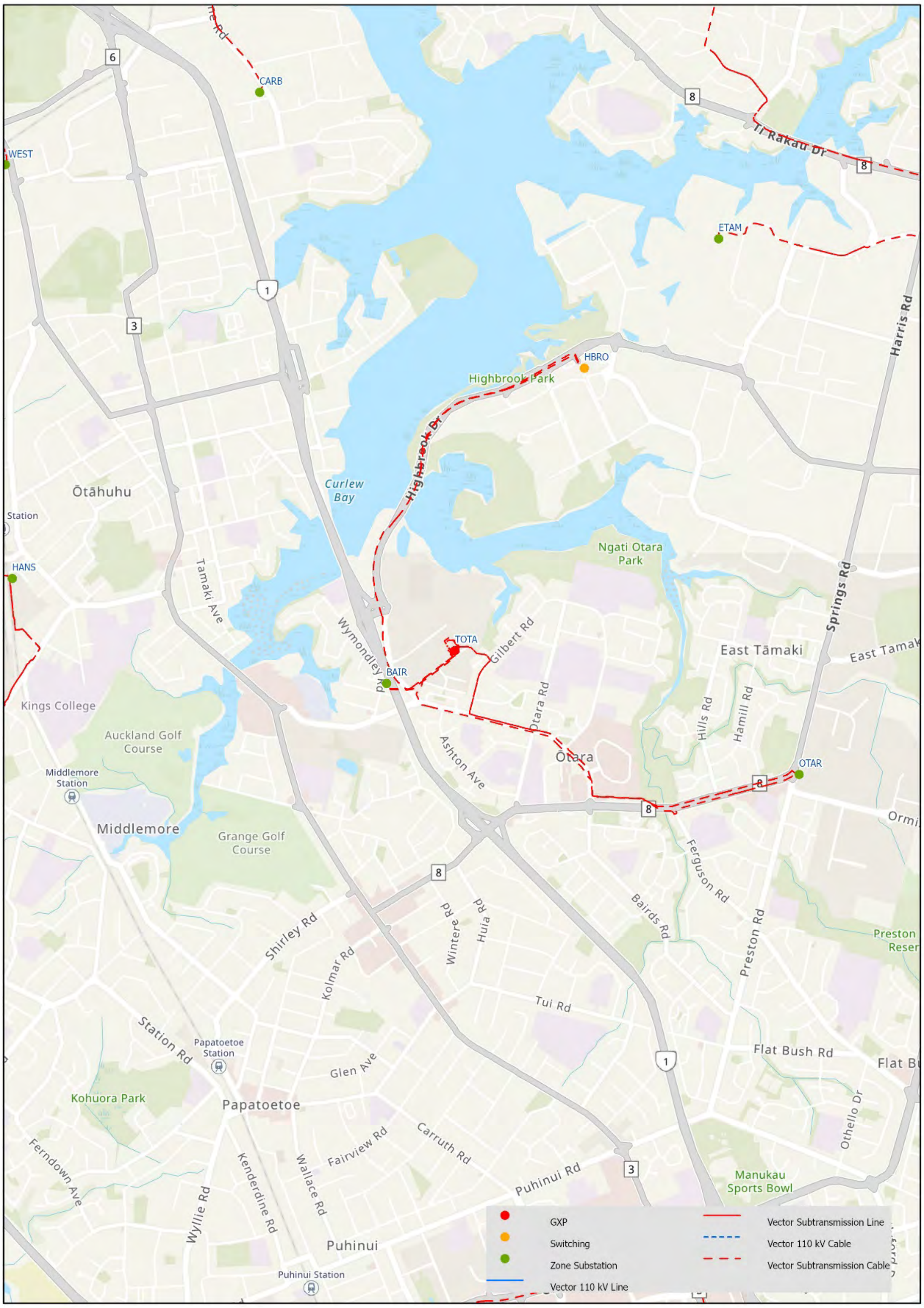


FIGURE 10.23: OTAHUHU SUBTRANSMISSION NETWORK

10.7.13.2 SUBTRANSMISSION

The area is supplied from the Otahuhu GXP. The subtransmission network operates at 22 kV and consists of underground cables that supply three zone substations. Bairds ZSS and Otara ZSS are supplied radially and Highbrook is supplied by a closed subtransmission loop.

There are no subtransmission security constraints identified to occur during the AMP period.

10.7.13.3 ZONE SUBSTATION

Bairds ZSS and Otara ZSS have 22/11 kV transformers and the distribution network from these substations operates at 11 kV. Highbrook is a switching station, i.e. it does not have transformers and supplies the distribution network which operates at 22 kV. Hence, the two 22 kV cable supplies from Otahuhu GXP that supply Highbrook are considered to be subtransmission due to their function, while the 22 kV feeders used for distribution are considered distribution feeders (similar to Auckland CBD).

There are no security constraints identified to occur at zone substations during the AMP period.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Bairds	RES	23.2	23.4	23.7	23.9	24.2	25.0	25.8	26.6	27.4	28.3	29.9
Winter	Highbrook	COM	11.3	11.2	11.2	11.1	11.1	11.1	11.2	11.2	11.3	11.3	11.5
Winter	Otara	COM	26.5	26.8	27.1	28.4	30.3	31.5	32.7	33.9	35.0	36.1	38.3

TABLE 10-28: OTAHUHU LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.13.4 DISTRIBUTION NETWORK

As noted above, the distribution network from Bairds ZSS and Otara ZSS operates at 11 kV and can be supported by adjacent substations, however the distribution network from Highbrook operates at 22 kV and is an isolated network with no distribution feeder ties to other zone substations. While there is negligeable industrial growth in the Highbrook region, there is sufficient capacity to supply future growth without breaching the SoSS.

Vector has identified an 11 kV feeder from Otara ZSS that will breach the SoSS in FY30. To resolve this issue, the preferred solution is to install an RMU to provide connection to an adjacent feeder and rebalance load across the feeders.

As a result of an E-Bus depot and organic growth, a capacity shortfall will occur towards the end of the AMP period, which requires a new feeder in Chapel Heights.

10.7.13.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Otara K15 11 kV feeder breaches SoSS	Otara - K15 11 kV feeder capacity optimisation - RMU installation	FY29	0.4
Otara K01 and K07 breaches SoSS	Otara Chapel Heights 11 kV feeder new	FY32	2.8

TABLE 10-29: OTAHUHU PLANNING AREA CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

10.7.14 WIRI PLANNING AREA

10.7.14.1 OVERVIEW

Wiri planning area supplies Manukau CBD and Wiri Industrial area. Development of the greenfields area towards Auckland Airport into an industrial subdivision is expected. Redevelopment of the old quarry site and nearby areas introduce large industrial loads that are expected to require connection within the next few years. The load increase is forecast to be 56 MVA in total by 2033 and Vector plans to partially supply it from the new West Wiri ZSS, which is under construction and is expected to be commissioned in FY24.

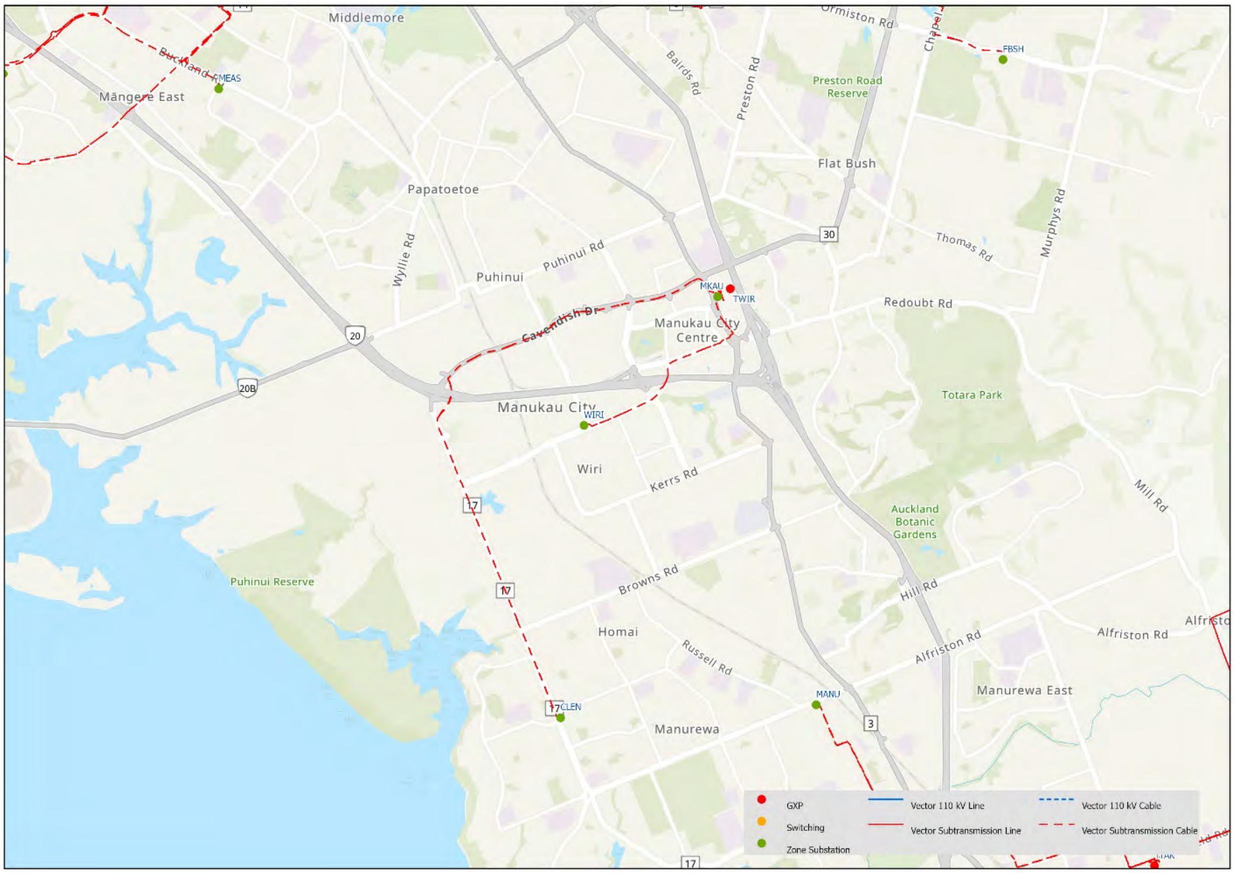


FIGURE 10.24: WIRI SUBTRANSMISSION NETWORK

10.7.14.2 SUBTRANSMISSION

The area is supplied from the Wiri GXP. The subtransmission network operates at 33 kV and consists of underground cables that radially supply three zone substations: Clendon ZSS, Manukau ZSS and Wiri ZSS.

There are no subtransmission security constraints identified to occur during the AMP period.

10.7.14.3 ZONE SUBSTATION

There are three zone substations currently supplying the Wiri area.

Expanding commercial development west of Roscommon Road and along Puhunui Road towards the airport is driving growth and causing forecasts of demand on Wiri zone substation to jeopardise capacity and SoSS constraints by FY24.

A fourth zone substation (West Wiri) is undergoing detailed design with an expected commissioning date of FY24.

			LOAD FORECAST (MVA)										
SEASON	ZONE SUBSTATION	SOSS CATEGORY	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter	Clendon	RES	22.2	22.3	22.5	22.6	22.7	23.2	23.6	24.1	24.5	25.0	25.8
Winter	Manukau	COM	31.4	31.9	32.4	32.8	33.3	34.5	35.7	36.9	38.2	39.4	41.5
Summer	Wiri	COM	32.2	32.4	32.6	32.8	33.0	33.9	34.7	35.6	36.4	37.3	39.0
Summer	West Wiri	COM	-	18.7	26.2	28.2	30.2	32.2	34.2	34.2	34.2	34.2	34.2

TABLE 10-30: WIRI LOAD FORECAST AND FORECASTED BREACHES OF THE SECURITY OF SUPPLY STANDARD (SOSS)

10.7.14.4 DISTRIBUTION

The distribution feeders from Wiri westward towards the airport are close to full capacity and are forecast to breach the SoSS in FY24. This will be resolved by reconfiguring loads across Wiri ZSS and the future West Wiri ZSS once it is commissioned in FY24.

10.7.14.5 CONSTRAINTS AND SOLUTIONS

CONSTRAINT	SOLUTION / PROJECT NAME	COMMISSIONING FY	ESTIMATED INVESTMENT $M
Significant increase in demand due to several large customers and residential load growth will cause a breach of the SoSS	New zone substation - West Wiri	FY24	8.2[1]

TABLE 10-31: WIRI CONSTRAINTS AND NETWORK REINFORCEMENT PROJECTS

[1] Only the cost falling within this AMP period is shown, the project commenced prior to this period.

10.7.15 NETWORK-WIDE ALLOCATIONS AND FUTURE CAPABILITY PROGRAMMES

10.7.15.1 HV REINFORCEMENT AND MONITORING

Our system growth process identifies the major constraints, projects and related budgets, as presented above. While great care is taken in this process to capture all the projects, smaller reactive reinforcement needs or unforeseeable changes may occur that require additional projects. An annual provisional allocation is included in our AMP to cater for HV reinforcements that may arise during the year and need to be carried out with urgency. A similar allocation for the opportunistic installation of future-proofing cable ducts for future reinforcement projects is also included. Civil works are the most expensive component of cable projects so by installing future-proofing ducts during roading alterations, overall costs are reduced.

Dedicated power-quality monitoring (PQM) capability is deployed across approximately half of our zone substations and all GXPs. By trending PQ changes over time, PQ deterioration can be observed, causes can be identified (in particular by relating customer plant outage times to network voltage sags/swells) and remedial steps can be taken if necessary. Also, monitoring of power quality is increasingly important as more inverter-based resources connect to the network. Our PQM programme is progressively extending the PQ capability across the remaining zone substations.

10.7.15.2 LV REINFORCEMENT AND MONITORING

In the absence of any LV network visibility, legacy practice is to address LV capacity and voltage constraints on a reactive basis. Informed by historic expenditure, an allocation for LV network reinforcement is included. Additionally, new DER connections will increase the need for reinforcement and the increase in LV visibility capabilities will surface constraints not captured reactively. An additional allocation is made to cover those LV reinforcements.

Due to the significant customer-driven changes on the LV network, dedicated LV monitoring equipment will be installed where most needed with the goal to progressively reach about 20% coverage by the end of the AMP period. This equipment will complement the smart meter information.

10.7.15.3 DEMAND-SIDE MANAGEMENT

Demand-side management and the use of NWAs underpin our Symphony strategy (See Section 2 and case studies on EV smart charging and smart hot water trials). A DERMS platform is essential to orchestrate the network and demand-side resources to mitigate constraints. Our experience has also shown that in some cases additional network monitoring, control and/or communication equipment needs to be installed on the network to support smart DER integration, which is covered by a dedicated budget allocation. To avoid network reinforcement in some parts of the network where a load management solution is used, we will also need to pro-actively install load management equipment to increase the load response or concentration levels. An allocation is made to cater for these investments. Both of those allocations are expected to be low in first half of the 10-year AMP period in line with Symphony Roadmap laid out in Section 2.

10.7.15.4 CONSTRAINTS AND SOLUTIONS

CONSTRAINTS	ALLOCATION / PROGRAMME NAME	INVESTMENT OVER 10 YEARS $M/YEAR
Un-foreseen HV network constraint	HV network reinforcement	2.28
Opportunistic installation of cable ducts	Futureproofing duct opportunities	1.13
Monitor power quality of the HV network	PQM rollout programme	0.16
Relieve LV network constraints	LV network reinforcement	2.9
Reinforce the network to relieve voltage and capacity constraints due to DER increase	DER (solar/EV) LV network reinforcement	1.86
Increase LV monitoring capability	LV network metering and monitoring	0.53
Missing network monitoring, control and/or communication equipment to orchestrate DERs	Smart DER integration for demand-side management	0.95
Insufficient concentration of smart demand-side devices to address constraint	Demand-side management roll out	1.91

TABLE 10-32: NETWORK-WIDE ALLOCATIONS AND FUTURE CAPABILITY PROGRAMMES

SECTION 10A

Appendix: Growth and security projects

10a –Growth and security projects

10a.1 Appendix overview

This Appendix provides additional details of the constraints, options analysis, and preferred solution for major projects required within the next 5 years as outlined in Section 10 - Growth and Security.

Major growth and security projects are those exceeding $1M. Only major projects planned to commence within the next 5 years are listed. The rationale for only discussing the major 5-year projects in detail is due to the uncertainty of the load growth forecasts and the impact of new technologies on project timing beyond 5 years. The options analysis for projects that are already in formal delivery phase are not covered and were presented in previous AMPs.

Available options and preferred solutions on the listed major projects in this Appendix may change over time and cost estimates firmed up as projects move towards full funding approval and commencement. These projects are also all subject to detailed technical and financial scrutiny as part of Vector's governance approval process.

10a.2 Wellsford planning area

10a.2.1 SANDSPIT ZONE SUBSTATION NEW

SANDSPIT ZONE SUBSTATION NEW
CONSTRAINTS
Load growth in the Warkworth area will result in a shortfall in transformer capacity at Warkworth ZSS and Snells Beach ZSS
OPTIONS
1. **Do Nothing:** The existing transformers will become overloaded. Customers supplied from these two ZSS will increasingly suffer from supply reliability issues and possible equipment failure. This is not acceptable. 2. **Construct a new ZSS at Sandspit Rd (in between Warkworth and Snells Beach):** This will offload the transformers at Warkworth and Snells Beach and increase security of supply to both ZSSs. 3. **Install a second transformer at Snells Beach ZSS:** This will resolve the Snells Beach constraint, but not the Warkworth constraint. 4. **Upgrade the Warkworth ZSS transformers:** This will resolve the Warkworth constraint, but not the Snells Beach constraint. 5. **Construct Warkworth South ZSS:** This is a more expensive project than Options 1 and 2 and will resolve the Warkworth constraint but not the Snells Beach constraint.
PREFERRED SOLUTION
Option 2 is the preferred initial solution since it resolves the constraints at both Warkworth and Snells Beach zone substations. The other solutions will still be required later – see below.

10a.2.2 WARKWORTH SOUTH ZONE SUBSTATION NEW

WARKWORTH SOUTH ZONE SUBSTATION NEW
CONSTRAINT
The load on Warkworth substation is approaching its firm capacity and 11 kV network capacity in Warkworth township will become constrained. There is also a need for 33 kV switchgear at this substation to terminate a 33 kV circuit from Wellsford ZSS.
OPTIONS
1. **Do Nothing:** Doing nothing will result in breach of SoSS in the Warkworth network. This option is not acceptable. 2. **Construct Sandspit ZSS:** This will offload the transformers at Warkworth and Snells Beach and increase security of supply to both ZSSs. It will not address 11 kV network constraints in Warkworth township. 3. **Construct Mahurangi ZSS:** This site is not ideally located for the near-term load growth. 4. **Upgrade Warkworth ZSS transformers and reinforce 11 kV network:** This option proposes installing larger transformers at Warkworth to increase the firm capacity of the substation. Warkworth substation is located 4 km away from the township and load centre, resulting in considerable and unnecessary expenditure on 11 kV feeders to deliver the distant capacity to the township. When compared to Option 1 this solution is not only costlier but does not provide the security that two substations can offer (Option 1 and Option 4).

5. **Construct Warkworth South ZS:** This option proposes a new 33/11 kV zone substation in Glenmore Road, Warkworth, on a site owned by Vector. In 2012 a new 33 kV feeder was constructed to Woodcocks Road (currently operating at 11 kV) in anticipation of supplying a future Warkworth South substation. Construction of Warkworth South substation will move the load centre from Warkworth substation (4 km out of town) to the centre of the "future urban" zone.

PREFERRED SOLUTION

After Option 2 is delivered in FY25, Option 4 is preferred as the subsequent capacity increase. Building a new Warkworth South zone substation will relieve the emerging feeder capacity and SoSS constraints at Warkworth.

10a.2.3 WELLSFORD ZSS TO WARKWORTH 33 KV SUBT CABLE STAGE 2

WELLSFORD ZSS TO WARKWORTH 33 KV SUBT CABLE STAGE 2

CONSTRAINT

The peak demand on the Wellsford ZSS to Warkworth ZSS 33 kV overhead lines is approaching the firm capacity.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS for Warkworth ZSS, Snells Beach ZSS and Omaha ZSS from 2024. This option is not acceptable.
2. **Install a third sub-transmission circuit:** The new sub-transmission cable will add capacity to the rapidly growing Warkworth area. The first stage of this cable installation is currently being delivered and the second stage will be delivered in FY24.
3. **Implementation of non-wires alternative**: The load growth is high and this option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 2 is the preferred option as it will increase sub-transmission capacity in the Wellsford/Warkworth area.

10a.3 Silverdale planning area

10a.3.1 DAIRY FLAT LAND PURCHASE FOR ZSS

DAIRY FLAT LAND PURCHASE FOR ZSS

CONSTRAINT

A new zone substation at Dairy Flat in the 2030s was part of the long-term strategy for the Redvale/Dairy Flat/Okura area. A new major point load in the area has brought forward the Dairy Flat ZSS construction to 2025 and a site for this will be secured.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Spur Road and Coatesville substations from 2025. This option is not acceptable.
2. **Early acquisition of a zone substation land at Dairy Flat site:** Identify and purchase a site for a future substation at Dairy Flat site at an early design stage of the development. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is Option 2 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably.

10a.3.2 DAIRY FLAT ZSS STAGE 3 3RD TRANSFORMER AND SUBTRANSMISSION CIRCUITS

DAIRY FLAT ZSS STAGE 3 3RD TRANSFORMER AND SUBTRANSMISSION CIRCUITS

CONSTRAINT

A new zone substation at Dairy Flat in the 2030s was part of the long-term strategy for the Redvale/Dairy Flat/Okura area. A new major point load in the area has brought forward the Dairy Flat ZSS construction with 2 transformers to 2025. Forecast load growth will require the installation of a third transformer at Dairy Flat ZSS to provide extra capacity, and a new subtransmission circuit from Albany GXP to maintain security of supply.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at the proposed Dairy Flat substation from 2028. This option is not acceptable.
2. **Install a third transformer and sub-transmission cable:** The third transformer and sub-transmission cable will add capacity to the substation and allow for future commercial and residential developments in the area. There will be space for a third transformer on site.
3. **Construct a separate new ZSS:** For local load growth and reinforce the subtransmission network to supply both ZSSs. This is a much more expensive option.
4. **Implementation of non-wires alternative:** The growth is high and is primarily Light Industrial. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area.

10a.3.3 OREWA ZSS SUBTRANSMISSION CABLE REINFORCEMENT

OREWA ZSS SUBTRANSMISSION CABLE REINFORCEMENT

CONSTRAINT

Orewa sub transmission breaches security of supply standard.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Orewa substations from 2025. This option is not acceptable.
2. **Replace the short sections of cable which are limiting the circuit ratings:** This would cost less than Option 3 but does not provide the same increase in security of supply.
3. **Install a new Transpower Silverdale to Orewa ZSS subtransmission circuit:** While futureproof ducts have been installed on about half the route length, this is still much more expensive than Option 2. It may still be required in the longer term but would be deferred by Option 2. Adding a third circuit would increase the security of supply into Orewa-Red Beach.

PREFERRED SOLUTION

Option 2 is the most cost-effective option in the short term to prevent cable overloading. To further increase capacity to the area when needed and provide improved network resilience and reliability of supply. Option 3 will be considered outside of this AMP period.

10a.3.4 MILLWATER ZONE SUBSTATION NEW

MILLWATER ZONE SUBSTATION NEW

CONSTRAINT

New residential developments are expanding westwards from Millwater towards Wainui and Dairy Flat. Distribution feeders supplying Millwater and Milldale greenfields residential developments are forecast to breach capacity and SoSS by 2027.

OPTIONS

1. **Do Nothing:** Existing Milldale feeder cables will become overloaded.
2. **Provide feeders from Spur Road ZSS:** Supplying the Millwater area from Spur Road ZSS would require very costly 11 kV cabling and an expansion of the newly installed switchboard. The spare capacity at the Orewa, Red Beach and Spur Rd ZSS would be exhausted in the medium term, requiring the bringing forward of the proposed Dairy Flat ZSS.
3. **Build new zone substation at Millwater:** Building Millwater ZSS will provide the required capacity to improve the security of supply to Millwater and the new Milldale greenfield development area.
4. **Install feeder cables from Orewa ZSS, Red Beach ZSS and/or Spur Road ZSS:** This would require very costly 11 kV cabling and switchgear extensions at both substations to supply Milldale. The spare capacity at the Orewa, Red Beach and Spur Rd ZSS would be exhausted in the medium term, requiring the bringing forward of the proposed Dairy Flat ZSS.
5. **Supply Milldale from Dairy Flat zone substation:** Dairy Flat ZSS will be required in any case, but it is more efficient to install the capacity near the load centre. A large investment in 11 kV network would be needed to bring capacity to Millwater from Dairy Flat.
6. **Implementation of non-wires alternative:** The growth is high and includes a large commercial point load. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 3 is preferred as it provides the most efficient solution for improved network security and resilience. The Millwater ZSS site is close to the major load centres and is better located than more distant alternative substations.

10a.4 Henderson planning area

10a.4.1 FRED TAYLOR DRIVE 11 KV REINFORCEMENT

FRED TAYLOR DRIVE 11 KV REINFORCEMENT

CONSTRAINT

Continuing strong commercial load growth in Westgate means the 11 kV network will become capacity constrained and the security of supply standard will not be met.

OPTIONS

1. **Do nothing:** This option will result in breach of capacity and SoSS for Westgate feeders. This option is not acceptable.
2. **Install new 11 kV feeders:** This option will solve the capacity and security breach problem in Westgate.
3. **Implementation of non-wires alternative**: The growth is high and is primarily commercial. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 2 is preferred because it is an efficient solution to solve the capacity and security breach constraint.

10a.4.2 HENDERSON GXP REDHILLS SUBTRANSMISSION FUTURE-PROOFING DUCTS

HENDERSON GXP REDHILLS SUBTRANSMISSION FUTURE-PROOFING DUCTS

CONSTRAINT

The existing Special Housing Area at Redhills is at the design and early construction stage and will comprise 5000 new dwellings. The wider area is forecast to double this. The existing network does not have sufficient capacity to meet these long-term load requirements. Redhills ZSS is scheduled to be constructed by 2029 and will require a new subtransmission circuit from Henderson GXP. A third-party cable installation in 2023-2024 is on the same route and this project will install future-proofing ducts for the Redhills cable.

OPTIONS

1. **Do Nothing**: Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Install future-proofing duct**: A third party is carrying out project works on the cable route. Ducts will be installed in combination with the works to reduce the cost and public disruption of the standalone civil project later.
3. **Undertake civil works with cable installation**: The civil works will be carried out as part of the cable installation. This will involve re-entering public roads and creating distribution after the third-party works (mentioned in Option 2) have been completed.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.4.3 SWANSON SECOND 33/11 KV TRANSFORMER

SWANSON SECOND 33/11 KV TRANSFORMER

CONSTRAINT

Increasing demand is forecasted to result in SoSS breaches at Simpson Road ZSS and Ranui ZSS by more than 1 MVA in 2026 and increasing, and at Swanson ZSS the transformer 15 MVA capacity limit will be reached by 2029.

OPTIONS

1. **Do Nothing:** The existing Swanson transformer will become overloaded. Customers supplied from these three ZSS will increasingly suffer from supply reliability issues and possible equipment failure. This is not acceptable.
2. **Install second transformers at both Simpson Road (15 MVA) and Ranui (20 MVA) ZSS**. Eliminates future SoSS breaches at each of these zone substations, and both substations have space to install a second transformer.
3. **Install a second 12.5 MVA or 15 MVA transformer at Swanson ZSS.** A second transformer addresses the backstop capacity shortfalls at both Simpson Road and Ranui ZSS, in addition to the constraint that develops at Swanson by 2029. This is the least cost option.
4. **Build a new zone 2x20 MVA substation (Waitakere ZSS)**. A new zone substation at Waitakere would address the developing constraints, but the cost of establishing a new substation is much higher than the reinforcement of an existing site.

5. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-wires alternatives will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 3 is preferred. The cost is less than both Options 2 and 4, and it relieves the developing constraints at all three zone substations. The cost of a new zone substation plus an 11 kV cable network is much greater than upgrading an existing zone substation.

10a.4.4 REDHILLS LAND PURCHASE FOR ZSS

REDHILLS LAND PURCHASE FOR ZSS

CONSTRAINT

The existing Special Housing Area at Redhills is at the design stage and will comprise 5,000 new dwellings. The wider area is forecast to double this. The existing network does not have sufficient capacity to meet these long-term load requirements. A new zone substation will be required, and this project is to secure a substation site in anticipation of this expansion.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS, this option is not acceptable.
2. **Early land acquisition of a zone substation land at Redhills site:** This ensures a suitable site is acquired in advance of the design process.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition, and risk not being able to secure a suitable.

PREFERRED SOLUTION

The preferred option is Option 2 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably

10a.4.5 REDHILLS ZONE SUBSTATION NEW

REDHILLS ZONE SUBSTATION NEW

CONSTRAINT

The existing network within the Redhills area is not capable of supplying the forecasted load, particularly on Ranui, Westgate and Riverhead feeders (also note comments for project about Redhills land purchase for ZSS)

OPTIONS

1. **Do Nothing:** Existing Ranui, Westgate and Riverhead feeders will become overloaded. Customers supplied from these feeders will increasingly suffer from supply reliability issues and possible equipment failure. This is not acceptable.
2. **Install new 11 kV cables into Redhills from Whenuapai ZSS and Westgate ZSS feeders:** This would be an expensive solution, and while it would defer the ZSS project for a few years, would result in stranded investment in 11 kV network after the ZSS is commissioned.
3. **Construct a new ZSS in Redhills:** This option represents a lower total cost than Option 2 and alleviates the constraint.
4. **Implementation of non-wires alternative**: The growth is high with large housing infill. This option will not adequately address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 3 is preferred. Building a new Redhills zone substation will relieve the emerging feeder capacity and SoSS constraints Redhills.

10a.4.6 RIVERHEAD 33/11 KV TRANSFORMER CAPACITY UPGRADE AND 11 KV SWITCHGEAR

RIVERHEAD 33/11 KV TRANSFORMER CAPACITY UPGRADE AND 11 KV SWITCHGEAR

CONSTRAINT

Load growth because of housing intensification in the Riverhead area will result in a shortfall in transformer capacity at Riverhead ZSS

OPTIONS

1. **Do nothing:** Existing transformers will become overloaded. Customers supplied from these transformers will increasingly suffer from supply reliability issues and possible equipment failure, this is not acceptable.
2. **Construct Kumeu ZSS:** While development in Huapai/Kumeu will require a ZSS in the future, this will be a high-cost project and is not ideally located to meet the near-term growth in the Riverhead area.
3. **Replace Riverhead transformers and switchgear:** This meets the medium-term requirements of load growth in Riverhead/Kumeu and increases security of supply into Waimauku, Whenuapai and Redhills.

PREFERRED SOLUTION

Option 3 is preferred due to the rapid growth and capacity constraint in the Riverhead area, and it defers the more expensive Option 2.

10a.4.7 WAIMAUKU ZSS 33/11 KV T2 TRANSFORMER CAPACITY UPGRADE AND 11 KV SWITCHGEAR

WAIMAUKU ZSS 33/11 KV T2 TRANSFORMER CAPACITY UPGRADE AND 11 KV SWITCHGEAR

CONSTRAINT

Load growth in the Waimauku area will result in a shortfall in transformer capacity at Waimauku ZSS

OPTIONS

1. **Do nothing:** Existing T2 transformer will become overloaded. Customers supplied from this transformer will increasingly suffer from supply reliability issues and possible equipment failure, this is not acceptable.
2. **Construct Kumeu ZSS:** While development in Huapai/Kumeu will require a ZSS in the future, this will be a much more expensive project requiring long subtransmission circuits and a land purchase.
3. **Replace Waimauku transformers and switchgear:** This meets the medium-term requirements of load growth in Waimauku and increases security of supply into the Muriwai, Waimauku and Huapai areas.
4. **Implementation of non-wires alternative**: This option does not adequately alleviate the transformer capacity shortfall for Waimauku and does not provide the same security of supply to the wider area

PREFERRED SOLUTION

Option 3 is preferred as a lower cost solution, deferring the more expensive Option 2.

10a.5 Hepburn planning area

10a.5.1 BRICKWORKS 33/11 KV SECOND TRANSFORMER, 11 KV SWITCHGEAR REPLACEMENT, AND NEW 33 KV CABLE

BRICKWORKS 33/11 KV SECOND TRANSFORMER, 11 KV SWITCHGEAR REPLACEMENT, AND NEW 33 KV CABLE

CONSTRAINT

Transformer loading at Brickworks breaches security of supply FY28, with neighbouring New Lynn ZSS transformer breaching security of supply in 2029.

OPTIONS

1. **Do Nothing:** Existing transformers will become overloaded. Customers supplied from these transformers will increasingly suffer from supply reliability issues and possible equipment failure. This is not acceptable.
2. **Install new 15 MVA transformer T2 and a subtransmission cable at Brickworks alongside existing 15 MVA T1:** The additional capacity will defer further investment for a few years but does not provide sufficient capacity for all the forecast load growth.
3. **Install two new 20/28 MVA transformers and a subtransmission cable at Brickworks:** Two larger transformers will provide sufficient capacity for the foreseeable future.
4. **Upgrade New Lynn ZSS transformers and install new 11 kV feeders from New Lynn to the Brickworks network:** The New Lynn transformers will need to be upgraded in the future to meet local load growth, but it is more economic to add the capacity where it is required (Brickworks first), avoiding the need for 11 kV reinforcement to transfer load between the sites.
5. **Implementation of non-wires alternative:** The growth is primarily commercial. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 3 is preferred, upgrade Brickworks ZS transformer to 2x20/28 MVA with a second subtransmission circuit. Option 2 (2x15 MVA transformers) will not adequately provide for forecast load growth and means New Lynn ZS will need a transformer upgrade in FY37.

10a.6 Albany planning area

10a.6.1 ALBANY GXP GREENHITHE NEW SUBTRANSMISSION CABLE

ALBANY GXP GREENHITHE NEW SUBTRANSMISSION CABLE
ALBANY TO GREENHITHE 110 KV TO 33 KV SUBTRANSMISSION OVERHEAD CONVERSION

CONSTRAINT

The Albany GXP to Greenhithe ZSS subtransmission cable is forecast to overload following an outage of the Greenhithe to Hobsonville Point ZSS circuit.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Install a new cable to bypass the constrained cable:** This will resolve the constraint for several years, and there is an opportunity to share civil costs with other projects on the same route.
3. **Convert Albany-Greenhithe-Wairau 110 kV circuit to 33 kV to create a new subtransmission connection to Greenhithe:** This requires the prior installation of Transpower's 220/33 kV T9 transformer at Wairau ZSS, which will not be completed in time to resolve this constraint. For this reason, and due to the opportunity to share civil costs, Option 2 is chosen for delivery first (2024). The 110-33 kV conversion project is scheduled for FY25-26.
4. **Implementation of non-wires alternative**: The growth is high and includes large commercial point loads. This option will not address the capacity and security shortfalls.

PREFERRED SOLUTION

Option 2 is the most cost-efficient option and resolves the constraint in the short term. Option 3 is scheduled to follow in 2026.

10a.6.2 ALBANY GXP ROSEDALE SUBTRANSMISSION CABLE REINFORCEMENT

ALBANY GXP ROSEDALE SUBTRANSMISSION CABLE REINFORCEMENT

CONSTRAINT

Rosedale subtransmission becomes constrained in FY29.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Upgrade the existing Albany-Rosedale subtransmission circuit and install a second circuit:** This option will re-purpose sections of two Albany-Wairau 110 kV lines after they are de-commissioned to save cable installation costs.
3. **Upgrade two Albany-Bush Road subtransmission circuits:** Due to the cable route length this is a more expensive solution than option 2. **Upgrade the Albany-Sunset Road subtransmission circuit.** Due to the cable route length this is an expensive solution which adds less capacity into the Rosedale-Sunnynook area than options 2 or 3.

PREFERRED SOLUTION

Option 2 is the preferred solution at present.

10a.6.3 ROSEDALE NEW 11 KV TRITON DRIVE FEEDER

ROSEDALE NEW 11 KV TRITON DRIVE FEEDER

CONSTRAINT

Rosedale 11 kV Arrenway Drive feeder becomes capacity constrained in FY24 and Apollo Drive feeder experiences backstop shortfall from FY29, due to an increase in the forecasted load at the Rosedale ZSS.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Create a new feeder (Triton Drive) from Rosedale ZSS to take load from the two existing feeders:** This option increases feeder capacity and improves backstopping capability within the Rosedale 11 kV feeder network.
3. **Replace the constrained cable sections in the existing feeder:** This would cost similar is to Option 2 but provides much less capacity increase.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the capacity and security breach problem for long term.

10a.6.4 ROSEDALE RD (TRITON DR TO TAWA DR) FUTURE-PROOFING DUCTS

ROSEDALE RD (TRITON DR TO TAWA DR) FUTURE-PROOFING DUCTS

CONSTRAINT

As the demand grows at Rosedale ZSS the security of supply standard will not be met. A future project Albany GXP Rosedale Subtransmission Cable Reinforcement (10A.6.2) will require 33 kV cable ducts along Rosedale Rd. Roadworks on part of the route provide an opportunity to install future-proofing ducts, saving costs and the disruption of a separate civil project.

OPTIONS

1. **Do Nothing**: Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies and increasing unreliability.
2. **Install future-proofing duct:** A Waka Kotahi project is upgrading the road on the cable route. Ducts will be installed in combination with the roadworks to reduce the cost and public disruption of the standalone civil project later.
3. **Do civil works with cable installation**: The civil works will be carried out as part of the cable installation. This will involve re-entering public roads and creating distribution after the third-party works (mentioned in Option 2) have been completed.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost-efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.6.5 EAST COAST ROAD ZS 2ND 33/11 KV TX & 33 KV CABLE

EAST COAST ROAD ZS 2ND 33/11 KV TX & 33 KV CABLE

CONSTRAINT

Load growth will result in a shortfall in transformer capacity. Brought forward due to updated load forecast; budget increased due to change in scope.

OPTIONS

1. **Do nothing:** accept the reduction in security of supply. This does not meet the Security of Supply standard.
2. **Install a 2nd transformer and 2nd subtrans cable from Rosedale ZSS:** This option increases transformer and subtransmission capacity at Rosedale and utilises synergies of works.
3. **Install a 2nd transformer and 33 kV switchboard to connect the two transformers to the existing single subtrans cable:** This option offers reduced security of supply compared to option 2.
4. **Transfer load to adjacent ZSS:** This would defer this constraint by a few years but bring forward constraints at other ZSS.

PREFERRED SOLUTION

Option 2 is the preferred solution because it provides better security of supply compared to Option 3.

10a.7 Wairau planning area

10a.7.1 BELMONT 33/11 KV TRANSFORMER T3

BELMONT 33/11 KV TRANSFORMER T3

CONSTRAINT

Ngataringa Bay ZSS in Stanley Point is prone to the risk of flooding in the event of a king tide, an event that has already occurred, and one that is estimated to be a 1-in-10-year or more frequent event in future. Flooding of the ZSS could result in loss of supply to all customers presently supplied from this ZSS.

The ZSS is supplied by an ageing 33 kV oil-filled submarine cable crossing the bay, which poses an environmental risk of oil pollution if it fails or is mechanically damaged and the oil containment elements of its design are compromised.

Besides, Ngataringa Bay ZSS has insufficient 11 kV backstop capacity for an outage at peak demand, hence breaching the SoSS.

OPTIONS

1. **Do Nothing**: The environmental and security of supply risks posed by the single ageing oil-filled submarine cable and by the flooding of Ngataringa Bay zone substation remain. Ngataringa Bay backstop shortfall remains.
2. **Install 3rd transformer at Belmont:** To eliminate the risk to the network that would occur if Ngataringa Bay ZSS is inundated, customers presently supplied by 11 kV feeders from Ngataringa Bay ZSS would in future be supplied by new 11 kV feeders from Belmont ZSS. A 3rd 33/11 kV transformer would be installed at the Belmont zone substation to accommodate the additional 11 kV demand. The 11 kV switchboard at Belmont ZSS would be extended to accommodate the additional 11 kV transformer feeder and the additional 11 kV feeders to Stanley Point.
3. **Relocate Ngataringa Bay ZSS**: Acquire land and build a new zone substation in a suitable flood risk-free location in Stanley Point; remove (or drain and seal) the existing 33 kV oil-filled submarine cable and replace it with a modern XLPE equivalent; reroute existing 11 kV feeders to suit the new location of the ZSS. The key environmental and security of supply risks would be avoided.
4. **Rebuild Ngataringa Bay ZSS**: Rebuild the zone substation in its existing location, but on elevated foundations to eliminate the security of supply risk posed by the existing low-lying installation; remove (or drain and seal) the existing 33 kV oil-filled submarine cable and replace with a modern XLPE equivalent.

PREFERRED SOLUTION

Option 2 is preferred at a significantly lower cost than options 3 or 4. It also provides several outcomes for the area: alleviation of flood risk, alleviation of environmental pollution risk; and integration of the future Belmont ZSS transformer replacement.

10a.7.2 HIGHBURY 33/11 KV SECOND TRANSFORMER AND SECOND 33 KV CABLE

HIGHBURY 33/11 KV SECOND TRANSFORMER AND SECOND 33 KV CABLE

CONSTRAINT

As a result of E-Ferry and organic growth, Highbury zone substation is reaching capacity in 2026. The peak demand is forecast to increase by 8MVA over the next ten-year period. There is insufficient spare capacity at peak demand to provide backstop to neighbouring zone substations.

OPTIONS

1. **Do nothing:** accept Highbury substation is at capacity and supply to customers will become increasingly unreliable.
2. **Install a second transformer and sub-transmission cable:** the second transformer and sub-transmission cable will add capacity to the substation and allow for future commercial and residential developments in the area. There is space for a second transformer on site.
3. **Implement non-wires solutions:** The growth on this substation is dominated by a large point load from the E-Ferry. This option is expected to have little benefit from economic and network improvement due to the large point load.

PREFERRED SOLUTION

Option 2 is preferred due to the growth and capacity constraint in the area.

10a.7.3 NORTHCROFT 11 KV REINFORCEMENT

NORTHCROFT 11 KV REINFORCEMENT

CONSTRAINT

As a result of organic growth, a backstop shortfall will occur on Takapuna K11 from FY28, which requires feeder reinforcement.

OPTIONS

1. **Do nothing:** This option will result in breach SoSS and thereby risking the loss of customer supplies and increasing unreliability. This option is not acceptable.
2. **Reinforce the 11 kV feeder:** This option will extend 11 kV feeder and create new backstopping links to solve the security breach problem on Takapuna K11.

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the security breach problem for long term.

10a.8 Auckland CBD planning area

10a.8.1 CBD 22 KV EXTENSION AIREDALE ST

CBD 22 KV EXTENSION AIREDALE ST

CONSTRAINT

The existing 11 kV PILC cable in Queen St need to be replaced due to poor condition. As the substitution for the replacement of the 11 kV PILC cable in Queen St, this project is to install new 22 kV cables extending the 22 kV network from Mayoral Dr to Airedale St and Queen St, install new 22 kV switchgear and transformers to convert the selected 11 kV substations to 22 kV, and connect the converted substations to the extended 22 kV network. The 11 kV PILC cable in Queen St will then be abandoned.

OPTIONS

1. **Do nothing:** The 11 kV PILC cable in Queen St will be replaced by a future asset replacement project. This option will be costly and lead to additional public disruption of Queen St, CBD. It is also not in line with Vector's long-term CBD plan to progressively shift the distribution network to 22 kV and phase out 11 kV network eventually.
2. **Install 22 kV cables and equipment to convert and transfer the portion of the 11 kV network to 22 kV:** This option enables the 11 kV PILC cable in Queen St to be abandoned. It is a cost-efficient solution for long term. It is in line with Vector's long-term plan for the CBD distribution network.

PREFERRED SOLUTION

Option 2 is the preferred solution. It is cost-efficient and aligns to the long-term strategy for the CBD distribution network.

10a.8.2 CBD 22 KV EXTENSION EMILY PLACE

CBD 22 KV EXTENSION EMILY PLACE

CONSTRAINT

The existing 11 kV PILC cable in Emily Place needs to be replaced due to poor condition. As the substitution for the replacement of the 11 kV PILC cable in Emily Place, this project is to install new 22 kV cables extending the 22 kV network in Emily Place, install new 22 kV switchgear and transformers to convert the selected 11 kV substations to 22 kV, and connect the converted substations to the extended 22 kV network. The 11 kV PILC cable in Emily Place will then be abandoned.

OPTIONS

1. **Do Nothing**: The 11 kV PILC cable in Emily Place will be replaced by asset replacement project. This option will be costly and lead to additional public disruption in CBD. It's not in line with Vector's long-term plan for the distribution network in CBD, which is to progressively extend 22 kV distribution network and phase out 11 kV network eventually.
2. **Install 22 kV cables and equipment to convert and transfer the portion of the 11 kV network to 22 kV:** This option enables the 11 kV PILC cable in Emily Place to be abandoned and takes advantage of synergies from third-party works. It is a cost-efficient solution for long term. It is in line with Vector's long-term plan for CBD distribution network.

PREFERRED SOLUTION

Option 2 is the preferred solution. It is cost-efficient and aligns to the long-term strategy for the CBD distribution network.

10a.8.3 CBD HOBSON ST BRADNOR LANE 22 KV EXTENSION

CBD HOBSON ST BRADNOR LANE 22 KV EXTENSION

CONSTRAINT

Long-term growth forecasts indicate a general need to extend the 22 kV distribution network across the CBD, to future-proof the 22 kV distribution network against the impacts of long-term growth. It is strategically important to secure the route for the installation of new 22 kV feeders from Hobson substation to the CBD area.

OPTIONS

1. **Do Nothing**: Long-term growth forecasts make an extension of the 22 kV network into this area inevitable; doing nothing at this stage will defer the extension until such a time that increased cost and disruption will have a higher long-term financial and reputational impact on Vector and will risk Vector being completely locked out from access to the already congested sub-grade services available to all utilities.
2. **Extend 22 kV distribution network**: Install sub-grade services and future-proof the 22 kV distribution network to enable further expansion of the network in the heart of Auckland CBD.
3. **Install future-proofing ducts only:** This option will require excavations for pulling pits and joint bays when 22 kV cables are required to be installed in the future, which will result in disruption to the public traffic and higher cost comparing to Option 2.

PREFERRED SOLUTION
The preferred option is Option 2. The current significant development works within the CBD provide the opportunity to install services and facilities to future-proof the 22 kV network for further expansion. Failing to take advantage of this opportunity will risk significantly higher long-term financial and reputational impacts to Vector in the future.

10a.8.4 CBD QUAY 11 KV TO 22 KV CONVERSION FOR SECURITY

CBD QUAY 11 KV TO 22 KV CONVERSION FOR SECURITY
CONSTRAINT
As a result of commercial load growth, Quay 11 kV breaches security
OPTIONS
1. **Do nothing:** This will result in breach of security at Quay 11 kV by 2028, increasing level of unreliability and customer experiencing poor service 2. **Install additional 22/11 kV transformer at Quay substation:** This is not a cost-efficient option for long term nor in line with our long-term plan for CBD distribution network which is to progressively upgrade the network to 22 kV and phase out 11 kV eventually. 3. **Replace the existing two 22/11 kV transformers with larger transformers:** This is not a cost-efficient option for long term nor in line with our long-term plan for CBD distribution network which is to progressively upgrade the network to 22 kV and phase out 11 kV eventually. 4. **Convert selected 11 kV distribution substations to 22 kV and connect the converted substations to 22 kV distribution network:** This is a cost-efficient solution for long term and in line with our long-term plan for CBD.
PREFERRED SOLUTION
The preferred solution is Option 4 because it is a cost-efficient solution for long term and aligns to the long-term strategy for the CBD distribution network.

10a.8.5 HOBSON WATERFRONT 22 KV FEEDERS NEW

HOBSON WATERFRONT 22 KV FEEDERS NEW
CONSTRAINT
As a result of commercial load growth in Wynyard Quarter, a security shortfall will occur in Hobson J09 and HOBS J39.
OPTIONS
1. **Do Nothing:** This option will result in breaches of security limits in the existing two feeders Hobson J09 and J39. 2. **Install two new 22 kV feeders from the Hobson zone substation:** This option will off-load the existing two feeders supplying Wynyard Quarter and alleviate the constraint in the existing feeders. This option will also provide sufficient spare capacity to meet the load growth in the area for long term. 3. **Install two new 11 kV feeders:** Vector's overall CBD strategy is focussed on building a 22 kV CBD distribution network. New 11 kV feeders would not align with this strategy, as they would use the available space less effectively, each feeder will provide lower capacity, and would not provide shared increased capacity for further future expansion. 4. **Implementation of non-wires alternative:** The growth is high and includes large commercial buildings. This option is expected to have little benefit from economic and network security perspective.
PREFERRED SOLUTION
The preferred solution is Option 2 because it is a cost-efficient solution for long term and aligns to the long-term strategy for the CBD distribution network.

10a.8.6 K RD CRL OSD FUTURE-PROOFING DUCTS AND CABLES

K RD CRL OSD FUTURE-PROOFING DUCTS AND CABLES
CONSTRAINT
Long-term growth forecasts indicate a general need to extend the 22 kV distribution network across the CBD. Construction of the City Rail Link facilities in the K Rd Station area has presented a synergistic opportunity to extend the 22 kV network during the construction work and to future-proof the 22 kV distribution network against the impacts of long-term growth.

OPTIONS

1. **Do nothing:** This option will result in loss of the synergy opportunity to extend the 22 kV distribution network. It will lead to additional public disruption when we need to excavate the road to install 22 kV cables in future.
2. **Install ducts and cables to extend the 22 kV distribution network along with CRL project around K Rd Station area:** This is a cost-efficient solution for long term and in line with our long-term plan for CBD.
3. **Install future proofing ducts only:** This option will require excavations for pulling pits and joint bays when 22 kV cables are required to be installed in future, which will result in disruption to the public traffic and higher cost comparing to Option 2.

PREFERRED SOLUTION

The preferred solution is Option 2 because it is a cost-efficient solution for long term and aligns to the long-term strategy for the CBD distribution network.

10a.8.7 CBD TYLER ST EAST 22 KV EXTENSION

CBD TYLER ST EAST 22 KV EXTENSION

CONSTRAINT

Long-term growth forecasts indicate a general need to extend the 22 kV distribution network across the CBD. Construction of the City Rail Link facilities in the Britomart/Lower Queen St areas has presented a synergistic opportunity to extend the 22 kV network along Tyler Street during the construction work and to future-proof the 22 kV distribution network against the impacts of long-term growth.

OPTIONS

1. **Do Nothing**: Long-term growth forecasts make the extension of the 22 kV network in this area essential. Doing nothing at this stage will defer the extension until such a time that increased cost and disruption in this highly visible and patronised area of the CBD will have a higher long-term financial and reputational impact on Vector.
2. **Extend 22 kV distribution network**: Take advantage of the CRL construction work to future-proof the 22 kV distribution network to enable further expansion of the network in this extremely busy area of Auckland CBD.

PREFERRED SOLUTION

Option 2 is the preferred option. The current significant development works within the CBD provide the opportunity to install services and facilities to future-proof the 22 kV network for further expansion. Failing to take advantage of this opportunity will risk significantly higher long-term financial and reputational impacts to Vector in the future.

10a.9 Roskill planning area

10a.9.1 MT EDEN LAND PURCHASE FOR ZSS

MT EDEN LAND PURCHASE FOR ZSS

CONSTRAINT

Significant residential development is being planned in the Mt Eden precinct, the area between Newton and Kingsland and centred around Mt Eden railway station, which is being redeveloped as part of the City Rail Link project. At present, the area is mainly supplied by 11 kV feeders from Newton and Kingsland zone substations. Load forecasts show that both substations are expected to breach capacity and security constraints from FY30.

OPTIONS

1. **Do Nothing:** If a zone substation in the Mt Eden area does not proceed, increasing demand in the precinct will result in deteriorating capacity and breaches of the SoSS at Newton and Kingsland ZSSs from FY30. Also, network loss would be greater owing to the Mt Eden load having to be supplied over a greater distance than if there were a ZSS in closer proximity to the Mt Eden precinct load centre.
2. **Early identification and acquisition of a zone substation location within the Mt Eden precinct:** Identify and purchase a site for the location of a future substation in the Mt Eden area at an early design stage of the development in about FY25 or FY26. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly developing area.
3. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs of a new ZSS. The rapid pace of development will reduce the number of suitable available sites on which a new zone substation could be constructed. Failing to secure a site in good time may also result in having to add new load to Newton and Kingsland zone substations, resulting in a breach of Zone substation capacity and security at the substations from FY30.

PREFERRED SOLUTION

Option 2 is preferred. Securing an optimal site at an early stage of development will avoid a higher cost in a less optimal location for the new substation required from FY31.

10a.9.2 MT EDEN PRECINCT FUTUREPROOF DUCTS AND CABLES

MT EDEN PRECINCT FUTUREPROOF DUCTS AND CABLES

CONSTRAINT

As a result of Mt Eden precinct development, a capacity and security shortfall will occur at Newton ZSS and Kingsland 11 kV ZSS, which requires to establish a new ZSS in Mt Eden area. New cables will need to be installed when the new substation is established.

OPTIONS

1. **Do nothing:** This option will result in higher cost and significant disruption to the public when new cables are required to be installed along these major roads at later stage. It will also have adverse impact to Vector's reputation.
2. **Install future proofing ducts in coordination with CRL project:** This is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.9.3 SANDRINGHAM SUBTRANSMISSION UPGRADE

SANDRINGHAM SUBTRANSMISSION UPGRADE

CONSTRAINT

As a result of load growth including Kainga Ora housing development, a capacity and security shortfall will occur at Sandringham ZSS 22 kV around 2030, which requires to upgrade the subtransmission at the ZSS.

OPTIONS

1. **Do nothing:** This option will result in capacity breach at Sandringham 22 kV. This option is not acceptable.
2. **Off load Sandringham 22 kV:** This option is not practical due to network configuration.
3. **Install additional subtransmission circuit from Roskill GXP to Sandringham substation:** Replace 22 kV sub-transmission circuits which are underrated with higher capacity cables.
4. **Upgrade Sandringham substation to 33 kV:** This option will require significant funding to upgrade the existing 22 kV rated assets at all the ZSS currently supplied from Roskill 22 kV to 33 kV.
5. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-wires alternatives will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 3 is preferred at this stage, but option 4 will continue to be monitored before formally starting the project and ahead of the constraint in 2028.

10a.9.4 SANDRINGHAM STODDARD RD 11 KV FEEDERS NEW (KAINGA ORA DRIVEN)

SANDRINGHAM STODDARD RD 11 KV FEEDERS NEW (KAINGA ORA DRIVEN)

CONSTRAINT

As a result of Kainga Ora housing development in Mt Roskill area, a capacity and security shortfall will occur in Sandringham K18 and Avondale K06, which requires to install new feeders. Compared to AMP 2022, the RNF contribution was raised from 10% to 100% as the investment will be recovered through the growth charge.

OPTIONS

1. **Do nothing:** This option will result in breach of capacity and SoSS in feeder Sandringham K18. This option is not acceptable.
2. **Install new 11 kV feeders from Sandringham substation to Stoddard Rd.** This option will resolve the SoSS breaches in the two feeders within the Sandringham area, whilst providing a cost-efficient supply to Kainga Ora.

3. **Implement demand side management and non-wires alternative:** Due to the high growth from Kainga Ora housing development, this the load management does not provide sufficient benefit from an economic point of view (e.g. limit deferral).

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the problem of capacity and security shortfall in the existing network and provide sufficient capacity to meet the housing growth in the area for long term.

10a.9.5 CARRINGTON RD FUTURE-PROOFING DUCTS

CARRINGTON RD FUTURE-PROOFING DUCTS

CONSTRAINT

As a result of housing development on the ex-Unitec campus, the existing 11 kV feeders in the area will breach security in the long term. New feeders will be required to solve the problem. Also, new subtransmission cables will need to be installed for Mt Albert substation capacity upgrade.

OPTIONS

1. **Do nothing:** This option will result in higher cost and significant additional disruption to the public when, at later stage, new cables are required to be installed along this major road. It will also have adverse impact to Vector's reputation.
2. **Install future proofing ducts in coordination with Auckland Transports project:** This is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.10 Penrose planning area

10a.10.1 SOUTHDOWN LAND PURCHASE FOR ZSS

LAND PURCHASE AND DESIGNATION FOR SOUTHDOWN NEW SUBSTATION

CONSTRAINT

As a result of industrial load growth in south of Penrose area, the existing substations Te Papapa and Westfield are forecast to breach SoSS from 2035.

OPTIONS

1. **Do Nothing:** Doing nothing will result in breach of SoSS at Te Papapa and Westfield substations from 2035. This option is not acceptable.
2. **Add new transformers at Te Papapa and Westfield substation:** This option is expected to be more expensive than a new substation at Southdown as the cable routes would be longer.
3. **Early acquisition of a zone substation land at Southdown site:** Identify and purchase a site for a future substation at Southdown site at an early design stage of the development in about FY24. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
4. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is Option 3 to secure a future zone substation site. As a prudent network manager, Vector needs to identify and secure suitable future zone substation sites to ensure Vector can supply future developments cost effectively and reliably

10a.10.2 ST JOHNS PILKINGTON RD 11 KV FEEDERS NEW

ST JOHNS PILKINGTON RD 11 KV FEEDERS NEW

CONSTRAINT

As a result of Kainga Ora housing development in Tamaki area, a capacity and security shortfall will occur on three feeders (SJOH K02, MWEL K03 and MWEL K12) which requires to install new feeders.

OPTIONS

1. **Do nothing:** This option will result in breach of SoSS in multiple feeders. This option is not acceptable.
2. **Install two new 11 kV feeders from St Johns substation to Pilkington Rd:** connect the new feeders to the existing 11 kV network and rearrange the feeders in the area. This option will off load the heavily loaded feeders and solve the problem of security breach.
3. **Implement demand side management and non-wires alternative:** This option is expected to have little benefit from an economic and network improvement point of view, due to the high growth rate from Kainga Ora's housing development.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is a cost-efficient solution to meet the load growth in the area for long term.

10a.10.3 ONEHUNGA 11 KV REINFORCEMENT

ONEHUNGA 11 KV REINFORCEMENT

CONSTRAINT

Install two new 11 kV feeders from Onehunga substation to Princes St via Selwyn St connecting to the existing network and rearrange the feeders in the area.

OPTIONS

1. **Do nothing:** This option will result in breach of capacity and SoSS in feeder ONEH K02 from 2030. This option is not acceptable.
2. **Install two new 11 kV feeders from Onehunga substation to Princes St via Selwyn St:** This option will solve the capacity and security breach problem in ONEH K02, and off load ONHE K12 therefore defer the reinforcement required for ONEH K12 at later stage.
3. **Implement demand side management and non-wires alternative:** This is an industrial area with limited demand-side flexibility

PREFERRED SOLUTION

Option 2 is preferred because it is a cost-efficient solution to solve the capacity and security breach problem for long term.

10a.10.4 TAMAKI FP MERTON RD AND APIRANA AVE

TAMAKI FP MERTON RD AND APIRANA AV

CONSTRAINT

As a result of Kainga Ora housing development in the Tamaki area, a capacity and security shortfall will occur at St Johns subtransmission and ZSS, which requires to establish a new ZSS in Tamaki area. Subtransmission and 11 kV cables will need to be installed when the new substation is established.

OPTIONS

1. **Do nothing:** This option will result in higher cost and significant disruption to the public when new cables are required to be installed along these major roads at later stage. It will also have adverse impact to Vector's reputation.
2. **Install future proofing ducts in coordination with Auckland Transport's and Watercare's projects:** This is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

PREFERRED SOLUTION

Option 2 is the preferred solution because it is cost efficient taking the synergy opportunity. It will also avoid the disruption to public when new cables are required to be installed at later stage.

10a.10.5 TAMAKI LAND PURCHASE FOR ZSS

TAMAKI LAND PURCHASE FOR ZSS

CONSTRAINT

Tāmaki Regeneration is a 30-year housing intensification project being undertaken by Kāinga Ora in Tāmaki area. The area is mainly supplied by 11 kV feeders from St Johns, Mt Wellington, Glen Innes, St Heliers and Orakei zone substations. St Johns, St Heliers and Orakei substations are supplied from a 33 kV switching station served as bulk supply point (BSP) within St Johns substation site. The BSP is supplied by three 33 kV circuits from Penrose GXP. Long-term load forecasts show that planned development in Tāmaki will cause demand on St Johns 33 kV BSP to breach SoSS from FY32.

OPTIONS

1. **Do Nothing:** Doing nothing will result in a new 11 kV load in Tāmaki being connected to the existing St Johns ZSS distribution network. This will result in breaches of SoSS requirement at St Johns zone substation on the 33 kV assets from FY32. Failure to secure an optimal site at the design stage of the development will result in a higher cost to establish the new substation in future.
2. **Add new 11 kV feeders to Glen Innes zone substation:** Adding new feeders to Glen Innes ZSS will reduce the short-term impact on St Johns ZSS, but it is expected to be more expensive than from St Johns ZSS due to the longer cable route lengths involved.
3. **Early identification and acquisition of a zone substation location within the Tāmaki Regeneration area:** Identify and purchase a site for the location of a future substation in the Tāmaki Regeneration area at an early design stage of the development in about FY24. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.
4. **Defer acquisition of zone substation location:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

PREFERRED SOLUTION

The preferred option is Option 3. Identification and acquisition of land for a new substation in Tāmaki area around FY24. Securing an optimal site at the design stage of the development will avoid a higher cost to establish the new substation forecast to be required from FY32.

10a.11 Pakuranga planning area

10a.11.1 HOWICK BUCKLANDS BEACH 11 KV FEEDER NEW

HOWICK BUCKLANDS BEACH 11 KV FEEDER NEW

CONSTRAINT

As a result of E-Ferry and organic growth in the Bucklands Beach area, the Howick Bucklands Beach 11 kV feeder is reaching capacity in 2029. The neighbouring feeders are similarly limited in capacity and connectivity given the area is on a peninsula and therefore geographically constrained.

OPTIONS

1. **Do nothing:** Accept one feeder at full capacity in 2029 and insufficient capacity available for new developments for load increases in the area.
2. **Install a new feeder:** This option will relieve the load the Howick Bucklands Beach 11 kV feeder and provide backstopping capacity to the neighbouring feeders.
3. **Implement demand side management and non-wires alternatives:** The growth on this feeder is dominated by a large point load from the E-Ferry. This option is expected to have little benefit from economic and network improvement due to the large point load.

PREFERRED SOLUTION

Option 2 is the preferred solution. It will increase capacity and security to the area and is the most cost-efficient solution to meet the load growth in the area.

10a.12 Mangere planning area

10a.12.1 MANGERE SOUTH LAND PURCHASE FOR ZSS

MANGERE SOUTH LAND PURCHASE FOR ZSS

CONSTRAINT

Expansion of the Watercare wastewater treatment plant at Mangere, along with commercial and residential developments around the airport and Mangere area will result in Mangere Central substation breaching SoSS in 2030.

OPTIONS

1. **Do Nothing:** Failure to secure a site for Mangere South ZSS in good time will jeopardise Vector's ability to secure a suitable site at a reasonable price and may delay the construction of the ZSS beyond FY29. Consequently, customers supplied from Mangere Central ZSS will increasingly suffer from supply reliability issues and possible equipment failure from FY30.
2. **Defer acquisition of land and build of zone substation:** Defer site acquisition until shortly before the location must be locked in to allow final detailed designs for the new ZSS. The rapid pace of redevelopment will reduce the number of suitable available sites on which a new zone substation could be constructed and therefore increase the cost of acquisition.

3. **Early identification and acquisition of a zone substation location within the southern Mangere area:** Identify and acquire a suitable site for the location of a future Mangere South zone substation in reasonable proximity to forecast load growth centres. Early action will avoid having to resort to a less optimal location later and will avoid having to compete and possibly pay a premium for space within an area already rapidly growing development.

PREFERRED SOLUTION

The preferred option is Option 3. It is prudent to identify and acquire a suitable ZSS site close to future load centres before suitable sites become unavailable to Vector.

10a.12.2 MANGERE SOUTH ZONE SUBSTATION NEW

MANGERE SOUTH ZONE SUBSTATION NEW

CONSTRAINT

Expansion of the Watercare wastewater treatment plant at Mangere, along with commercial and residential developments around the airport and Mangere area will result in Mangere Central substation breaching SoSS in 2030.

OPTIONS

1. **Do Nothing:** Existing feeders from Mangere Central and Mangere West substations will become overloaded. Customers supplied from Mangere Central ZSS will increasingly suffer from supply reliability issues and possible equipment failure from FY30.
2. **Build a new zone substation:** Build a new zone substation on the acquired land. This will provide the required capacity and alleviate constraint at Mangere Central.
3. **Install new 11 kV feeders from alternative ZSS:** There will not be any spare circuit breakers available at the neighbouring ZSS (Mangere West, Mangere Central by 2030. Additionally, this option would be expensive owing to the long cable route lengths to the development area. Planning reviews have also identified this option would be a temporary short-term solution due to the scale of the growth.

PREFERRED SOLUTION

Option 2 is preferred. Building a new Mangere South zone substation will relieve the emerging feeder capacity and SoSS constraints at Mangere Central.

10a.12.3 MANGERE CENTRAL ROBERTSON RD 11 KV FEEDER NEW

MANGERE CENTRAL ROBERTSON RD 11 KV FEEDER NEW

CONSTRAINT

Increasing residential development by Kainga Ora in Favona area will lead to a feeder (MEAS K16) exceeding capacity in 2028.

OPTIONS

1. **Do nothing:** Accept one feeder at full capacity in 2028 and insufficient capacity for new developments in the area.
2. **Install new feeder:** This option will relieve load on MEAS K16 and will add capacity to the area for Kainga Ora development.
3. **Implement demand side management and non-wires alternatives:** This area has a large residential component and implementation of non-network option such as smart hot water has been considered. The reduction in demand from controllable loads will not deliver a sufficient deferred project cost.

PREFERRED SOLUTION

Option 2 is the preferred option. This option addresses the feeder constraint and provides additional capacity to the high growth area.

10a.13 Takanini planning area

10a.13.1 MANUREWA ALFRISTON RD 11 KV FEEDER NEW

MANUREWA ALFRISTON RD 11 KV FEEDER NEW

CONSTRAINT

As a result of organic growth, two feeders in the area will be constrained. The Manurewa K12 feeder will reach capacity and have a backstop shortfall in 2029. The Manurewa K07 feeder will reach capacity in 2031 and have a backstop shortfall in 2034.

OPTIONS

1. **Do nothing:** Accept the feeder reaching full capacity and breaching backstopping in 2029. Supply to customers will become increasingly unreliable.
2. **Install a new 11 kV feeder:** Install a new feeder to relieve the load on Manurewa K12 feeder and provide additional capacity from the new feeder during contingency situations.
3. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of non-wires alternative will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is the preferred option. This option will increase capacity and security to the area is the most cost-efficient solution to meet the load growth in the area.

10a.13.2 MARAETAI SUBTRANSMISSION REINFORCEMENT

MARAETAI SUBTRANSMISSION REINFORCEMENT

CONSTRAINT

Maraetai subtransmission circuits supply three zone substations (Maraetai, Waiheke and Clevedon). Load growth at these substations is expected to double in the next 10 years. This includes organic growth at Maraetai and Waiheke, addition of E-Ferry, a large point load customer and a large greenfield development in the Beachlands. The increasing demand is forecasted to result in SoSS breach in 2026/27.

OPTIONS

1. **Do Nothing:** Accept the forecast SoSS breaches and overloads thereby risking the loss of customer supplies increasing unreliability. This will result in non-compliance with the SoSS.
2. **Reinforce the sub-transmission network:** Replace sections of the two 33 kV sub-transmission circuits which are underrated with higher capacity cables.
3. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of non-wires alternatives will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is the preferred option as increase capacity to the area and provides improved network resilience and customer reliability of supply.

10a.13.3 TAKANINI ZONE SUBSTATION CAPACITY UPGRADE

TAKANINI ZONE SUBSTATION CAPACITY UPGRADE

CONSTRAINT

Expansion of large commercial customers along with new commercial and residential develop around Takanini area will result in Takanini zone substation exceeding capacity in 2026.

OPTIONS

1. **Do nothing:** accept Takanini zone substation at full capacity and supply to customers will become increasingly unreliable.
2. **Install a third transformer and sub-transmission cable:** a third transformer will add capacity to the zone substation and allow for future commercial and residential developments in the area. There is space to install a third transformer on site.
3. **Implement demand side management and non-wires alternative:** This area has a large residential component and implementation of a non-wires alternative will be considered and subject to technology development, customer adoption and regulatory settings.

PREFERRED SOLUTION

Option 2 is preferred due to the rapid growth and capacity constraint in the area.

10a.14 Otahuhu planning area

There are no forecast growth or security related projects identified for the Otahuhu planning area that exceed $1m starting within the next five-year period or are not already in formal delivery.

10a.15 Wiri planning area

There are no forecast growth or security related projects identified for the Wiri planning area that exceed $1m starting within the next five-year period or are not already in formal delivery.

SECTION 11

Network resilience and reliability management

11 – Network resilience and reliability management

11.1 Overview

New Zealanders are relying more and more on access to affordable and reliably energy to live their day-to-day lives and network security and resilience are becoming increasingly important as customers increase their reliance on electricity for their day-to-day needs (communication, connectivity, working from home, electrification of transport etc). Network security is managed through several investment portfolios. This Section sets out the investment in both asset replacement and asset reinforcement categories with a specific focus on projects for the improvement and bolstering of network reliability and resilience, including managing the impacts of climate change as well as reducing our asset management carbon footprint.

11.2 Asset management objectives

The asset management objectives that are addressed through our network reliability and resilience investments are set out in the table below:

FOCUS AREA	OBJECTIVES
Safety, Environment and Network Security	• Comply with relevant safety and environmental legislation, regulation and planning requirements. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and Stakeholders	• Enable customers' future energy and technology choices. • Ensure the long-term interest of our customers by providing an affordable and equitable network.
Network Performance & Operations	• Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with Security of Supply Standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future Energy Network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience. – customer: decarbonisation of the economy, electrification of transport, etc. – operations: transition to distribution system operator model and whole-of-system planning. • Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

TABLE 11-1: ALIGNMENT WITH ASSET MANAGEMENT OBJECTIVES

11.3 Network reliability

11.3.1 STRATEGIC RELIABILITY MANAGEMENT PLAN (SRMP)

Over recent years we have accelerated specific programmes of work that reflect our commitment to quality compliance and the outcomes customers experience through the regulatory quality compliance framework. The Strategic Reliability Management Plan (SRMP) specifies how we will ensure compliance with quality standards and sustain this performance in future years, while not compromising health and safety outcomes, to meet the expectations of our customers and other stakeholders.

The reliability objectives and reliability strategies within the SRMP are a subset of Vector's broader set of asset management objectives and are governed by the Strategic Reliability Management (SRM) group. The SRMP builds upon the actions taken as part of our response to our reliability performance from RY2016-22, with a heightened focus on initiatives aimed at improving outage duration times, which has been identified as Vector's key reliability challenge, as well as reducing the number of customers impacted by events. There is an annual review process for the SRMP at the end of regulatory years which assesses all components of unplanned SAIFI and SAIDI performance including contribution by cause and the effectiveness of the initiatives during that year. Following that review process the SRMP is revised and some of the initiatives are embedded into business-as-usual practice while other new initiatives aligned to the reliability strategies are developed for the upcoming year and provided for in the expenditure profile.

We returned to quality compliance in both RY21 and RY22, and as of end of January 2023, unplanned SAIDI and SAIFI were on track to once again be compliant for RY23. However, the flood and storm events of January and February 2023 resulted in a SAIDI breach. SAIFI was not breached.. The SRMP and associated reliability management targets a margin below the regulatory limit to allow for the variability in network operating conditions from year to year.

In this section, we describe the ongoing strategies, investment and initiatives underpinning our Strategic Reliability Management Plan.

11.3.2 SRMP GOVERNANCE AND MONITORING OF RELIABILITY PERFORMANCE.

The SRM meeting is held fortnightly and comprises the following actions and objectives;

- Discuss outage events of note for the preceding two weeks to determine operational learnings and any emerging trends affecting reliability performance and customer experience
- Monitor status of most significant HV constraints, subtransmission security of supply risks and Transpower planned outages with potential to impact customers to ensure contingency plans are in place, so risk is mitigated
- Tracking of reliability performance for year-to-date, including by cause, to monitor progress against year-end internal targets and need to accelerate actions if required
- Monitoring of the SRMP and associated initiatives to ensure actions are completed on time and within allocated budget

11.4 Specific SRMP Initiatives

11.4.1 MICROGRIDS – GENERATORS AND ENERGY STORAGE

Microgrids are small, self-sustaining local power systems that provide valuable benefits to the communities they serve. Traditionally, outages have been managed by enhancing interconnectivity and backstopping but this is not economical or practicable in certain remote areas on the edge of the distribution network. Microgrids are small self-sustaining local energy grids that serve a relatively small geographic footprint with their own interconnected resources such as generators or energy storage devices and have the capability to island from the broader distribution network. They can include the use of mobile generation to mitigate the impact of increased planned work on the customer experience, fixed generation as a contingency plan to manage SAIDI on long rural feeders where other options to improve network resilience are not economically viable or, can be large scale batteries colloquially known as BESS systems (battery energy storage systems). Microgrids, where economically feasible, are an ideal solution for protecting remote communities from the impact of climate change.

11.4.2 RISK BASED VEGETATION MANAGEMENT

Vegetation strikes and damage, transient or sustained, are one of the most common causes of outages on Vector's network and with the change in climate this is becoming more prevalent. During the January 2023 storm event, the impact of vegetation was unprecedented. To manage the impact of vegetation, Vector utilises a risk-based approach to plan and then carry out remediation work. This involves an independent company to scope, plan and package the work using the risk-based approach and also carry out audits of work undertaken, in conjunction with Vector's in house expertise, to ensure work has been undertaken correctly. To deliver this work Vector engages two vegetation management businesses, along with others when required, to ensure that this targeted approach and the volumes of work can be achieved each year.

In 2021 a targeted rate for vegetation was implemented by the Auckland Council on Vector and to fund enhanced maintenance of Auckland Council-owned trees that present a risk to Vector's electricity network. Now that this programme has been in place for over two years, there is a review being undertaken into Vector's vegetation strategy and business rules to increase efficiencies with the Council programme while maintaining the risk-based approach.

11.4.3 DEPLOYMENT OF NETWORK AUTOMATION

Vector's SRMP strategy includes a programme to continue the deployment of automation and sectionalisation on the network. This programme provides for the automation for remote control of existing 11 kV switches and the rollout of new automated switches for remote control on 11 kV feeders over ten years. The programme was accelerated with the first six years of the deployment completed in 2021. The programme of automation is continuing. Further details on the nature of this initiative are provided further below.

Also included in this initiative is the development of a network automation integration strategy roadmap which will determine the use and further deployment of equipment such as Fault Passage Indicators (FPI) and Distance to Fault Technology (DTF) on the network to assist fault restoration. We are also implementing the use of smart meter technology to automatically detect and report on network outages.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
FPI Installation			0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	2.86

TABLE 11-2: FORECAST EXPENDITURE FPI INSTALLATION

11.4.4 FSP ENABLEMENT TO REDUCE THE DURATION TIME OF OUTAGES

Analysis undertaken as part of the SRMP identified that one of the primary issues faced by Vector was the response and restoration time for addressing network faults. Initiatives that were kicked off in RY20 to address this, are continuing and includes:

- An incentive scheme has been established for our FSPs concerning the average outage duration (CAIDI) performance for unplanned outages;
- A new sub-depot has been established at Warkworth in close proximity to the vast Northern overhead network to reduce the distances and times to reach fault locations;
- Additional fault passage indicators have been deployed in the network to enable quicker identification of the location of faults;
- Dispersed deployment of field service crews around the network (rather than located in main depots) to speed up response to faults; and
- Providing additional training and tools to field service crews to enable them to respond immediately to a greater variety of faults without requiring a second crew to arrive for assistance.
- The benefits of these initiatives continue to be observed and are reviewed annually as part of the SRMP.

11.4.5 CORRECTIVE MAINTENANCE STRATEGY AND IMPROVED INSPECTION TECHNIQUES

To accelerate the delivery of corrective work to reduce high priority condition notifications, with prioritization on SAIDI critical sections which reduces the overall SAIDI risk profile of the network, resources to specifically focus on this strategy were increased since RY21. This strategy includes improved inspections techniques in the field, improved recording of network faults via software on tablets by crews in the field and, an improvement in data quality through SAP PM. This strategy also includes a program of works using LiDAR inspection techniques that focuses on the identification and correction of clearances between overhead lines to ground, structures, buildings, waterways, etc. to ensure compliance with statutory requirements, more specifically NZECP34 [1] and reduce the risk of harm to the public.

Furthermore, thermographic, acoustic surveys and aerial surveys (UAV) are highly effective technologies to identify certain asset failure modes and are an on-going part of Vector's routine inspections and monitoring strategies for the overhead network and other asset classes going forward. These programmes are crucial to identify latent and inherent faults early and the associated corrective work enables Vector to proactively correct such latent and inherent faults in the network. Thermographic and acoustic inspections are embedded as business-as-usual corrective practices.

11.5 Ongoing reliability investments

11.5.1 APPLY SAFETY IN DESIGN

Vector has made Safety in Design (SiD) a mandatory requirement for Vector design and capital projects and SiD is embedded in the review process for the design of capital projects. For this purpose, Vector has developed a formal SiD standard, USH002 Networks Safety in Design, which sets out the minimum requirements to establish safety in design as early as possible in the design and throughout the life cycle of the asset.

This requires all parties to consult, co-operate and co-ordinate to eliminate or otherwise minimise risks in the design to prevent harm throughout the life of the asset being designed, as far as reasonably practicable. Safety in Design is a practice that integrates risk-management techniques into the design process early, to identify, assess and treat health and safety risks to people over the life of the asset being built. The transmission and distribution of high and low voltage electricity involve managing significant electrical hazards, and the Health and Safety at Work Act (HSWA) 2015 now places greater accountability on designers to achieve safe outcomes for the works they design.

Safety in Design means that the integration of control measures early in the design process eliminates, or, if this is not reasonably practicable, minimises the risks to health and safety throughout the life of the structure being designed. Safety in design applies to any plant, substance or structure that is constructed, whether fixed or movable. SiD will evolve to consider the impact of climate change to a much larger degree than in the past.

11.5.2 NETWORK ISOLATION AND AUTOMATION

A simple but effective way to reduce the impact of outages on customers is to install additional switching devices in the 11 kV distribution network that includes switches automated for remote control. Our strategy is to try and limit the number of customers impacted by an outage to less than 500. Under our automation and overhead switch replacements over the last AMP period a large number of overhead switching devices have been replaced with modern switching devices. Additional switches

[1] Code of Practice for Electrical Safety Clearances, NZECP 34

have also been installed in the network to reduce the number of customers impacted by an outage. Automated for remote control switches were installed in strategic locations in feeders to effect quick and easy switching during contingencies and for planned maintenance works. This program of work has had a material impact to reduce SAIDI and will continue in the forecast 10-year AMP period.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Northern Feeder Automation and isolation	0.33	0.50	1.66	1.74	1.57	1.57	1.41	1.41	1.41	1.41	13.00
Auckland Feeder Automation and isolation	0.99	0.83	2.36	2.28	2.44	2.44	2.61	2.61	2.61	2.61	21.78
Total	1.32	1.32	4.02	4.02	4.02	4.02	4.02	4.02	4.02	4.02	34.77

TABLE 11-3: FORECAST EXPENDITURE FOR NETWORK AUTOMATION AND ISOLATION

11.5.3 11 KV DISTRIBUTION CABLE REPLACEMENT

This reliability focused replacement program of works focuses on the proactive replacement of underground 11 kV cables. Vector's CBARM model for the underground 11 kV cable fleet is fully developed and this model is used to inform the program for proactive cable replacement. The focus of the program is on the ageing PILC cable fleets that were installed between the 1950s and 1980s. Distribution 11 kV cables have an average fault rate of 0.047 faults/km with most of these faults attributable to PILC cables. Most faults are found to originate from cable joints but the results of some of the pre-commissioning tests upon repair suggest a deterioration of the cable insulation. Auckland CBD is undergoing major and rapid development and the line-item titled Auckland opportunistic cable replacement in the financial table below, makes provision for the proactive replacement of ageing cable assets under major civil works upgrade in the Auckland CBD including the new underground central rail link and underground stations under a dig once, replace once approach to prevent continuous disruption to business owners and the public. The focus of this program is more on reliability than hardening against climate change.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland 11 kV cable replacement	0.50	0.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	29.00
Northern 11 kV cable replacement	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	5.00
Auckland opportunistic cable replacement	9.56	4.27	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	37.83
Total	10.56	5.27	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	71.83

TABLE 11-4: FORECAST EXPENDITURE 11 KV CABLE REPLACEMENT

11.5.4 REPLACEMENT OF 11 KV RING MAIN UNITS (RMU)

This reliability focused program of works focuses on ageing 11 kV oil filled RMUs such as the Long and Crawford population, and the combined population of series 1 Andelect/Astec/ABB SD RMU switchgears. The CBARM model for this asset type is fully developed and is used to inform the replacement program. From RY19 to RY21 this program was delayed, to make way for the SRMP automation initiative but this program is now back up to speed and is planned to continue throughout the AMP period. The new RMUs will be automated as and where required and those that are not automated will be able to be retrofitted with automation if such a requirement should arise. This program will not only improve the reliability and resilience of the network but also remove the risk of oil spills. The oil filled RMUs held risk to operators and its replacement will also improve operator safety (and by default, public safety). Even though this programme is more focused on reliability, the focus will also include climate change, especially flooding, to ensure RMUs are installed with least risk to flooding. i.e., perhaps elevated or in a different location less prone to flooding.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland RMU Replacement	*10.00*	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	90.90
Northern RMU Replacement	*1.00*	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	9.30
Total	*11.00* [1]	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	100.20

TABLE 11-5: FORECAST EXPENDITURE RMU REPLACEMENT

11.5.5 REPLACEMENT OF DISTRIBUTION TRANSFORMERS

To ensure the integrity of this simple but important asset population, ageing distribution transformers, both pole mount and ground mount, will be replaced (transformers smaller than 100 kVA will be run to failure). The replacement program is informed by our mature CBARM model for distribution transformers. Pole mounted distribution transformers will be installed with improved and more robust kingpins that hardens the installation. Pole mounted transformers will include lightning arrestors to

[1] Of the $11M allocation for FY24 for the proactive replacement of ring main units, $9.8M, has been forecast to be spent in FY23 under an accelerated programme of works, and not included in the total in this table.

harden the network against the impact of lightning over voltages. Under climate change increased lightning activity has been observed.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland distribution transformers replacement	*1.00*	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	9.00
Northern distribution transformers replacement	*3.33*	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	29.93
Total	*4.33* [1]	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33	4.33	38.93

TABLE 11-6: FORECAST EXPENDITURE DISTRIBUTER TRANSFORMER REPLACEMENT

11.5.6 REPLACEMENT OF OVERHEAD 11 KV SWITCHES

Vector's 11 kV overhead network includes a large number of air-break switches, disconnectors, fuses, isolating links, sectionalisers and reclosers. Vector does not have a CBARM model for its overhead 11 kV switch population but there is good record of failure modes as well as good maintenance records and records of defects that assist to inform our proactive replacement program. This program will replace like for like but where automation is needed, will replace a manual operated device with an automated device.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland overhead 11 kV switch renewal	*1.27*	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	11.46
Northern overhead 11 kV switch renewal	*0.50*	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	4.50
Total	*1.77* [2]	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	15.96

TABLE 11-7: FORECAST EXPENDITURE OVERHEAD 11 KV SWITCH RENEWAL

11.5.7 MICROGRID ROLLOUT

A large-scale battery system (BESS) was installed at Tapora in the far Northern Vector network in the extensive avocado growing region to provide respite during network outages. This BESS system can operate in a microgrid mode and supply the demand for a period of about 4 hours.

Ensuring reliability in remote areas using traditional network enhancement or backstopping solutions is often costly relative to the number of customers served and, in some instances, simply not practicable. We are always looking at smarter and cost-effective ways to meet the requirements of our customers in areas on the edges of our network with modest growth but with inadequate quality of supply performance. This is where employing self-sufficient microgrids can be a viable economic alternative. Most microgrids are network-connected, but they can 'island' themselves during an outage. This means those connected to them can access back-up power, and this cost-effectively improves remote communities' resilience.

Temporary generation was deployed in the rural enclaves of Piha and South Head in 2019 and this generation has proved to be well worth the investment and hugely successful in alleviating SAIDI and improving the customer experience. Customers have been vocal in stating their satisfaction and support for the generation installations. In this AMP period, permanent generation sites will be established at these two remote communities that are reliant on single and lengthy 11 kV supplies. Piha is supplied by a 62 km long 11 kV feeder that services 1,744 customers and South Head is supplied by a 116 km 11 kV feeder from Helensville ZSS that services 1,133 customers. Both these feeders are in the SAIDI top ten worst performing feeders, backstopping is not available, and a traditional network backstop solution is not economic. The higher capital cost of BESS systems compared to diesel generation has discounted the installation of BESS systems in these enclaves. Apart from the higher installation cost, BESS systems are not suitable as a backup supply for long outages typically associated with for example a car-versus-pole incident which, can typically take up to 8 hours to replace at which time a BESS would have run out of capacity. Permanent diesel generator installations will be deployed in these enclaves.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
South Head permanent standby generation		1.36									1.36
Piha permanent standby generation		1.63									1.63
Total		3.00									3.00

TABLE 11-8: FORECAST EXPENDITURE FOR PERMANENT STANDBY GENERATION

[1] Expenditure of the $4.3M allocated for proactive replacement of distribution transformers in FY24 has been brought forward to FY23 under an accelerated programme and, not included in the total in this table

[2] Expenditure of the $1.77M allocated for proactive replacement of overhead network switches in FY24 has been brought forward to FY23 under an accelerated programme and, not included in the total in this table

11.6 Managing carbon footprint

Vector has set a science aligned target to reduce Scope 1, and 2 emissions (excluding electricity distribution losses) by 53.5% by 2030 based on a 2020 baseline. The target has been set to meet the External Reporting Board's Climate Related Disclosure standards which Vector is obliged to comply with as a listed entity. Vector is also investigating Scope 3 reductions to meet Climate Leaders Coalition obligations, and is already working with supply chain partners, like our Field Service Providers, on reducing indirect emissions.

The table below outlines our emissions profile over the past three years. Vector's emissions based on our science aligned target have been increasing due to an increase in SF_6 related emissions because of switchgear failure. Vector's stationary combustion however has been decreasing since FY20 due to work in diesel generation optimisation, and the utilisation of mobile transformers for planned maintenance projects. Our largest source of emissions increase has been in Vector's Electricity Distribution Losses. We expect this emission to increase as our network grows to cater for the wider decarbonisation transition, and therefore exclude it from our science aligned targets.

ELECTRICITY DISTRIBUTION NETWORK

Emission Categories for BU	tCO2e - FY20	tCO2e - FY21	tCO2e - FY22
Scope 1 - Stationary combustion	3,339	2,750	3,096
Scope 1 - SF_6	425	591	1,858
Scope 1 - Vehicle Fleet	34*	36*	27*
Scope 1 - Refrigerant leakage	0.94*	0.73*	0.34*
Scope 1 – Total	**3,799**	**3,378**	**4,981**
Scope 2 - Electricity consumption	502	497	571
Scope 2 - Electricity Distribution Losses	32,504	33,622	39,078
Scope 2 – Total	**33,006**	**34,119**	**39,649**
Scope 3 - Fuel used by FSPs	6,474*	6,821*	6,450*
Scope 3 - Fuel- and Energy-related emissions	896*	754*	894*
Scope 3 - Business Travel	31*	5*	5*
Scope 3 – Total	**7,401**	**7,580**	**7,349**
Total	**44,206**	**45,077**	**51,979**
Biogenic emissions	162	133	150
Science-aligned target emissions	**4,463**	**4,008**	**5,702**

* A small percentage of these emissions arise from activities shared with Vector's Gas distribution and Fibre businesses. We are working towards separating all emissions data from FY23.

TABLE 11-9: SCOPE 1,2,3 EMISSIONS FOR VECTOR'S ELECTRICAL NETWORK

11.6.1 DIESEL GENERATION REDUCTION (STATIONARY COMBUSTION)

The largest lever for distribution decarbonisation lays in the reduction of temporary diesel generation during planned construction works or planned maintenance works. Temporary generation is required to maintain supply when the plant to be worked on needs to be de-energized. The present strategy focuses on better management of diesel generators, and the use of mobile transformers as an alternative to diesel generation. Such initiatives not only reduce emissions but also noise, street pollution, urgency of the shutdown window, and overall cost. For more information refer to our Greenhouse Gas Emissions Inventory Report [1]. Note that the Diesel Generators used as standby generators for emergencies, such as those in Piha and Southhead represent only 0.5% of overall diesel emissions and can therefore be considered negligible.

11.6.2 SF_6

SF_6 emissions have increased in 2022 due to leaks in major SF_6 switchgear as a result of seal failures. As SF_6 comes under the emission trading scheme (ETS), Vector is obliged to purchase New Zealand Units (NZUs). SF_6 reduction can be achieved through

[1] https://www.vector.co.nz/investors/reports

improvements in monitoring and management. Nevertheless, failures will always occur, and the only solution to eliminate SF_6 emissions is through the installation of SF_6 free equipment.

11.6.3 NET ZERO OPERATIONS BY 2030 – REGULATORY ALLOWANCE FOR CARBON CREDITS

Vector is a member of the Climate Leaders Coalition, a CEO-led community of over 100 organisations representing 60% of New Zealand's gross emissions. As part of our 2017 obligation to the Climate Leaders Coalition, Vector has set a net-zero emission target of Scope 1 and 2 emissions (excluding electricity distribution losses) by 2030. Net-zero emissions is achieved through the purchase of carbon offsets on an international market. Assuming the science-based emission target is achieved, and the price of carbon is $140/tCO2e, Vector's electricity business would have an additional operating expenditure of $285k to meet this need. This allowance will be required from 2030 onwards.

11.6.4 CONSIDER ENVIRONMENTAL IMPACTS

The environmental effects of installing, operating, maintaining and upgrading Vector's network are regulated by a range of legislation and statutory controls - particularly the Resource Management Act 1991, as given effect to by the Auckland Unitary Plan.

Vector follows the processes and procedures and complies with the relevant regulations and standards, set by this framework. In some instances, this framework provides for Vector's assets and network activities as 'permitted activities'. The design and installation of upgrades in the network is undertaken in a way that ensures that permitted activity thresholds are applied. Where this is not possible, Vector obtains the requisite resource consents for its assets and related activities, which ensures the environmental effects of these are appropriately avoided, remedied, mitigated or minimized as far as is practicable.

11.7 Network resilience

Increased network hardening investment to adapt to the impacts of climate change is essential, not only to safeguard customer experience against increasing risk of weather-related disruption, but also to provide the increased resilience needed to match the increased criticality of the electricity system for energy, transport and the digital economy. The level of investment required now for network hardening is not recoverable through the current DPP3 allowances. Vector's view is that future DPP cycles must do more to account for the need for EDBs to invest in network hardening for climate change resilience. Extreme weather events affecting Auckland like the April 2018 storm, Auckland Anniversary flooding of January 2023, and Cyclone Gabrielle of February 2023 make this clear. Early and preliminary forecasts in this AMP have set an additional investment at around $135m through the DPP4 period, although we will more fully quantify the additional investment needed once further analysis is completed in time for our 2024-2034 AMP.

While we are still assessing the full extent of network damage and resilience response required following the extreme weather events of 2023, the following projects and programmes describe our plans and investments required to specifically address investment for network resilience in DPP4. The table below is our high-level provision for the DPP4 period and beyond.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Northern Subtrans Network Hardening			10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	80.00
Auckland Subtrans Network Hardening			5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	40.00
Northern Distribution Network Hardening			7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	60.00
Auckland Distribution Network Hardening			2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	20.00
Northern ZSS Reinforcement Network Hardening			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	8.00
Auckland ZSS Reinforcement Network Hardening			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	8.00
Total			27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	216.00

TABLE 11-10: NETWORK HARDENING FORECAST EXPENDITURE FOR FLOODS AND INUNDATION

11.7.1 FLOODS AND INUNDATION

Vector has been working with NIWA, and the University of Auckland's climate risk team to understand the impact of climate change on the electricity network. The January and February 2023 floods clearly showed the vulnerability of some parts of the electricity network. The Auckland Region Climate Change Projections and Impacts report from NIWA, and GIS modelling conducted against Vector's asset base provides us with a base level of knowledge to prepare for the impacts of climate change. Forecasting the impact of climate change disruption continue to be refined [1] as the latest climate science and socio-economic projections are formed.

The January and February 2023 weather events showed Auckland's vulnerability to flood risk and wind gusts of increasing strength and frequency, as well as cyclonic activity. There has been an increase in the severity and frequency of extreme or longtail weather events. In the summer months, Auckland can also be subject to periods of sustained dry weather that brings the risk of fire. If unmitigated, the afore mentioned will have an increasing detrimental impact on network reliability, resilience

[1] For more information, refer to Vector's taskforce on Climate Related Financial Disclosures (TCFD) report

and security of supply. The vulnerabilities of the network to flood and wind were particularly evident in low lying areas where zone substations flooded extensively and on steep hilly terrain where ground was washed away under the continuous rain, that then resulted in slips which in turn caused power poles and subtransmission masts to fail, fall or lean over. King tides commensurate with cyclonic weather activity has caused low lying substations close to the coastal plain or waterways to flood.

The photo below shows Wairau zone substation that is in an overland flood path. In this case the 33 kV/11 kV switchgear room was constructed at a height well above the flood plain. Extensive flood modelling at the time of design in 2013 determined the floor height should be for a 1-in-500-year flood and no damage was sustained to this facility during the 2023 weather events. However, the power transformers at Wairau, that were installed in the 1960's, all sustained damage to their control circuits that were not installed at height, at the time. This resulted in water penetration, damage and outages of transformers at this zone substation.

FIGURE 11.1: WAIRAU ZONE SUBSTATION – JANUARY 2023 FLOOD EVENT

11.7.2 NETWORK HARDENING FOR FLOOD AND INUNDATION

Our plan to harden the network against the impact of flooding and inundation will focus on zone substations and control equipment that are risk and prone to the impact of flooding and inundation. The following is a summary of projects that have been identified now:

- Re-engineering and relocation of outdoor installed transformer management systems and their associated RTUs that presently exist at low height in floodplains and flood-paths, into switchgear rooms which has floor levels elevated above flood path levels. Where this is not practicable, equipment will be elevated above flood levels and made weatherproof. As the photo above shows, the 33 kV and 11 kV switchgear at Wairau zone substation was safe from the January 2023 floods because the switch and control room were constructed well above the flood plain but the transformer control gear on all five transformers in the yard (not shown), sustained damage.
- At Waikaukau zone substation in Auckland's west, the transformers are located to the rear of the existing substation yard in the overland flood path and will be relocated to the front of the yard which is above the flood plain. Provision has been made in the AMP to relocate the transformers into full bunded enclosures that will be modelled and constructed to be above overland flood paths.
- Ngataringa zone substation is right on the edge of Ngataringa Bay and prone to king tide flooding. Network studies have shown that it is more beneficial to reinforce the network from Belmont zone substation to Ngataringa and beyond to Devonport than to elevate or relocate Ngataringa zone substation. Temporary measures will be instated at Ngataringa zone substation until its decommissioning, forecast for RY25.
- Waimauku zone substation in Waimauku village is in a wetland flood plain and its 11 kV switchgear is prone to flooding. The switchgear is forecast for replacement in the AMP window at which time it will be constructed to be above the flood plain. For the interim an investigation will be undertaken how to best mitigate the switchgear against the risk of inundation.
- Flooding issues were also experienced at Takapuna, Forest Hill, and Coatesville zone substations but the impact was less than at the afore-mentioned sites.

11.7.3 INCREASE IN WIND SPEED

A key threat to Vector's network is an increase in projected wind-gust events, since high wind speeds, storms and cyclonic events cause significant power outages and disruption to customers.

Figure 11.2 below details projections of hours of wind speeds per year greater than 70km/h. While we also have data for other windspeeds, 70km/h is the threshold at which network damage becomes material. As climate change modelling is a probabilistic exercise, we use the 95th percentile and 50th percentile as key indicators. We would expect a 5% probability of a 95th percentile year occurring, whereas a 50th percentile represents an average year.

In all climate scenarios there is an increase in hours of high wind speeds per year. The hothouse represents a worst-case climate change trajectory where the world maintains a business-as-usual trajectory of fossil fuel consumption. The disorderly decarbonisation scenario is a more probabilistic trajectory based on transitions that are occurring since the Paris Agreement. Nevertheless, this scenario still experiences a doubling of average hours of high wind speeds per year from 83 in 2005 to 181 hours in 2100, with the 95th percentile reaching up to 391 hours (nearly 5x as what we currently experience).

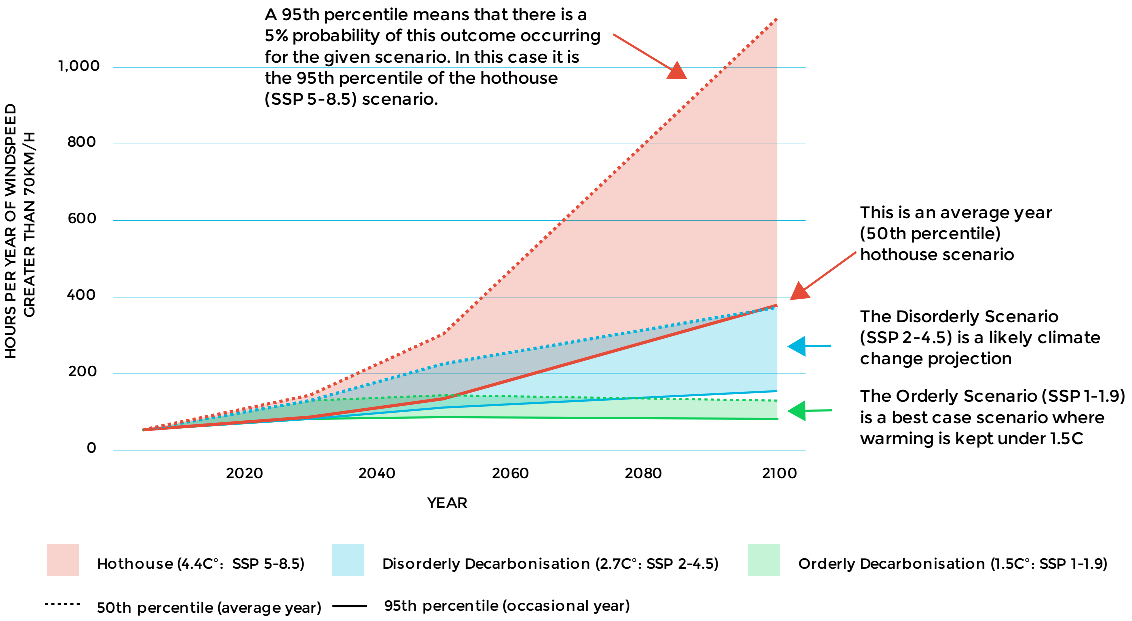


FIGURE 11.2: PROJECTED INCREASE IN HOURS OF WINDSPEEDS GREATER THAN 70KM/H OVER THREE CLIMATE CHANGE SCENARIOS

11.7.4 NETWORK HARDENING FOR INCREASE IN WIND SPEED

The risk associated with higher wind speeds was shown during the April 2018 storm and the severe winds of the January and February 2023 flood and storm events. This led to large numbers of outages and substantial damage in the network. A number of trees fell onto overhead lines during the January and February 2023 storms, example shown in the photo below.

FIGURE 11.3: FALLEN TREE ON 11 KV OVERHEAD LINE AT ORATIA - FEBRUARY 2023

Because the overhead network is most affected by wind, network hardening against the impact of wind naturally gravitates and focuses on the overhead network. Combined flood and wind events are known as cascading climate change impacts. This can cause increased tree-fall due to weakened geotechnical stability of the ground, landslips when the vegetation sits on steep terrain, and road closures that prevent lines from being repaired until flood waters subside. Network hardening for wind will include the following:

THE USE OF COVERED CONDUCTORS

Covered conductor that are fully insulated, so called "covered conductors thick (CCT)", can withstand the full operating voltage for a number of hours as well as withstand bark and branches rubbing against the conductor for a sustained period of time. This type of conductor thus has huge potential in terms of reducing the risk of network outages during storm events. Vector has installed CCT conductor in five trail sites and thus far these network portions have performed exceptionally well and holds real potential for a wider rollout especially in areas with high levels of vegetation.

THE USE OF COMPOSITE CROSSARMS

The crossarms across Vector's network are almost entirely hardwood and the vast majority is seasoned Australian hardwood. In the 2000's a noticeable deterioration in the performance of the Australian hardwood crossarms was noticed and a decision was made to switch to South American Purpleheart. However, the crossarm fleet is aging and continues to be a major contributor to SAIDI. After a number of successful trial installations using composite crossarms a decision was made to rollout composite crossarms in the 11 kV network as standard. This will provide much needed hardening because they provide improved basic impulse levels against lightning induced impulse voltages, have a higher resistance to fire than timber crossarms and negates the need to use hardwood timber from hardwood timber forests. They are also less prone to leeching and moss build-up. Furthermore, composite crossarms do not break easily and as a matter of fact, tend to bend rather than break. This has the advantage that when a tree falls onto an overhead line the composite crossarm will in most instances bend but still hold the conductors.

It has become clear that not all poor performing 11 kV overhead network portions require capital intensive full conductor replacement works but a proactive planned program that focuses on crossarm-replacement, will be sufficient to improve the performance of certain network portions. Such a program will go a long way to improve SAIDI and the customer experience (and commensurate service levels).

This reliability program will focus on the 11 kV network and replacements will be targeted in accordance with a prioritised list of 11 kV network portions and all crossarms in the identified area will be replaced in one go in each area to make a larger immediate impact on SAIFI (and SAIDI) and also reduce the requirements for traffic management and multiple outages.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland Crossarm Renewal	0.47	0.72	1.14	1.14	1.15	1.14	1.17	1.13	1.17	1.16	10.39
Northern Crossarm Renewal	1.86	2.88	4.56	4.57	4.61	4.55	4.68	4.50	4.69	4.66	41.56
Total	2.33	3.60	5.70	5.71	5.76	5.69	5.85	5.63	5.86	5.82	51.95

TABLE 11-11: FORECAST EXPENDITURE FOR CROSSARM REPLACEMENT

THE INCREASED USE OF LIGHTNING ARRESTORS

Climate change has seen increased lighting activity around the network but more specifically in the North-western network. 11 kV lightning arrestors will become part of our standard for overhead installations. And where appropriate in areas of high lightning activity. In areas of high lightning activity, lightning arrestors will be retrofitted to the network. This will reduce the risk of overvoltage related damage to plant.

OVERHEAD CONDUCTOR RENEWALS

The renewal of overhead conductors is an important reliability and climate change hardening program of works and focuses on the 11 kV network. This program has evolved to prioritise the areas for conductor renewal, using Vector's CBARM model, as well as SAIFI and SAIDI performance. Conductor renewal will by default include the replacement of crossarms with composite crossarms, replacement of class B insulators with class A post type insulators, lightning arrestors and if and as required, the replacement of pole structures to ensure the mechanical integrity of overhead line support structures. This holistic replacement approach will harden the overhead networks against the impact of increasing winds and storms in general as well as against lightning, all of which are the result of climate change. The replacement of conductors focuses on overhead line portions with small and aged conductors, most notable 16mm² copper conductors and 21mm² ACSR conductors. The Vector network has a sizeable population of these types of conductors.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Overhead Conductor Renewal	6.65	11.12	9.67	8.82	8.71	9.79	10.44	9.49	9.32	8.09	92.10

TABLE 11-12: FORECAST EXPENDITURE FOR OVERHEAD CONDUCTOR RENEWALS

11.7.5 CLIMATE CHANGE AND IMPACT ON GROUND GEOTECHNICAL CONDITIONS

The largest impact on the geotechnical conditions/stability of the soil happens during high and persistent levels of rain. This was particularly felt during the January 2023 storm in which numerous large slips occurred that impacted the overhead network, caused a significant number of outages and extensive damage to the overhead network. The photo below is an image of a leaning subtransmission tower in the suburb of Glenfield on Vector's 110 kV overhead line between Albany GXP and Wairau zone substation during the January 2023 storm. This tower failed during the persistent rain and resultant slip.

FIGURE 11.4: LEANING 110 KV SUBTRANMISSION TOWER, GLENFIELD, JANUARY 2023

11.7.6 HARDENING FOR GEOTECHNICAL

Vector's design standard and design guidelines for the installation of overhead lines are robust and allows for expected wind loads and predictive geotechnical conditions. Geotechnical risks, more specifically risk of slips, applies more to existing overhead lines that were installed on sloping ground in the past. Hardening for this aspect will thus focus on those portions of the overhead network that were prone to damage during recent storms with specific consideration of the January and February 2023 storms. Hardening will include a number of options, for example, complete rerouting of an overhead line if practicable and a route can be found or even undergrounding of a route or portion of a route. Hardening could also include the installation of piled concrete foundations or cast-in-situ foundations if practicable and geotech conditions allow or, some other form of structural support and strengthening. More investigative, design and planning effort is on-going into this hardening initiative.

11.7.7 INCREASING TEMPERATURES AND HOT DRY SUMMERS

Hot dry summers hold risk for both the overhead network as well as underground cables. The temperature and moisture in the earth surrounding an underground power cable have a direct impact on how much current can be carried before there is a risk of damage to the cable. We have developed an operating standard that sets out the actions to be undertaken during a hot dry summer, e.g. revising SCADA cable rating alarm levels to lower levels – essentially a form of dynamic ratings and transferring of load to other lower loaded feeders. We use NIWA supplied data from NIWA soil moisture monitoring station at three locations spread over the network and the application of different capacity ratings for our subtransmission cable fleet on a certain level of moisture in the earth.

With regard to 11 kV overhead distribution feeders, the risk of fire is most prevalent during hot dry summers because if a conductor should fail and fall into dry scrub or if an 11 kV dropout fuse should operate and cause molten metal to fall onto scrub there is a real risk of a fire. As part of our operating strategy for hot dry summers, reclosers are disabled at a certain minimum soil moisture content to reduce the risk of fire from overhead conductors. We also work very closely with NIWA and NZFS to ascertain areas of high risk during hot dry summers.

11.7.8 HARDENING FOR HOT DRY SUMMERS

In RY24 we will trial the use of current limiting expulsion drop out fuses in the 11 kV overhead network. These fuses are designed to limit the fault current to less than peak value that in turn reduces the risk of incendiary pieces that could start a brush fire in dry scrub. The use of this type of fuse will also have the advantage that the magnetic forces that can cause damage to conductors during a fault, will be reduced.

In RY24 we will also install seven Vector owned and operated soil moisture level testing stations to collect more detailed information with regard to moisture content and if and when cable ratings should be adjusted (reduced) to account for dry conditions.

EXPULSION DROP OUT FUSE REPLACEMENT

With climate change there is a risk and probability that hot and dry conditions can occur and perhaps increase which in turn leads to a higher risk of wildfires. The electricity network can contribute to the start of a wildfire if an expulsion drop-out fuse emits/ejects hot particles during operation to clear a fault. To reduce this risk Vector will install current limiting drop out fuses in a number of 11 kV overhead feeders in the Auckland and Northern networks. The performance of these feeders and current limiting fuses will then be closely monitored and if the performance of these new devices is to expectations, they will be rolled out network wide in the AMP period. These devices will provide reliability, safety and environmental improvements and hardening against climate change.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland expulsion drop out fuses replacement	0.20		0.26	0.26		0.26		0.26		0.26	1.47
Northern expulsion drop out fuses replacement	0.20		0.26	0.26		0.26		0.26		0.26	1.47
Total	0.39		0.51	0.51		0.51		0.51		0.51	2.94

TABLE 11-13: FORECAST EXPENDITURE FOR EXPULSION DROP OUT FUSE REPLACEMENT

11.8 Financial summary of reliability and climate change programmes of work

At the time of preparing the 2023 AMP, Vector was unable to complete our full assessment of network damage caused by the extreme weather events in January/February 2023. Vector will complete this assessment to inform a more detailed reliability and resilience network investment response for 2024 AMP. The investment forecast below provides a financial summary of the programmes of work that are already in progress to address network resilience, reliability, safety, and the environment but also includes our high-level forecast for programmes of work in the DPP4 period that will specifically focus on hardening the network to improve resilience for weather related events.

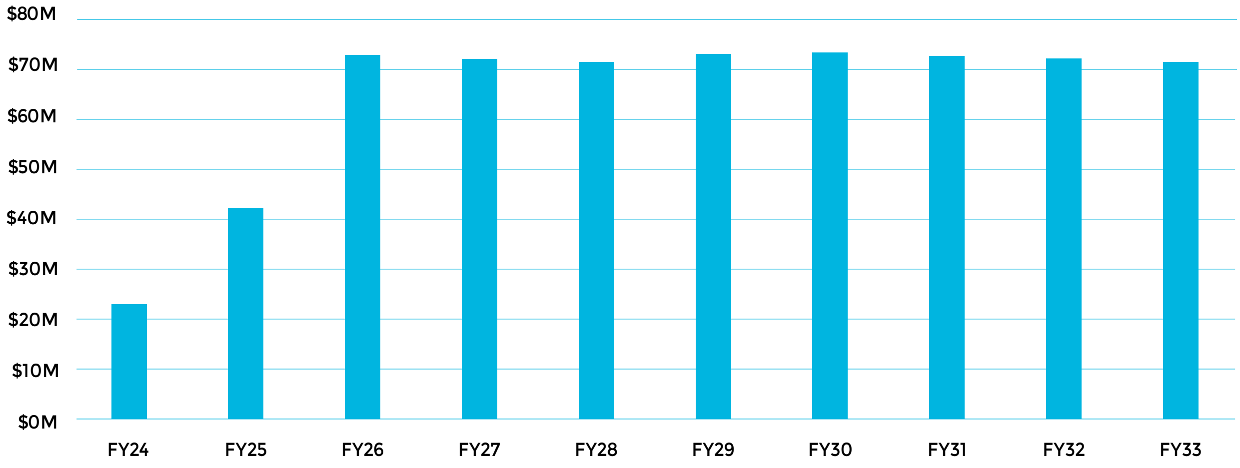


FIGURE 11.5: FORECAST RELIABILITY IMPROVEMENT AND CLIMATE CHANGE NETWORK HARDENING

SECTION 12

Asset replacement and renewal

12 –Our assets

Asset replacement and renewal is aimed at ensuring that the assets installed on the network are in serviceable condition and are replaced pro-actively (prior to failure) or reactively (after failure) according to their condition and criticality. Vector takes a whole of life cycle approach to assessing the need for asset replacement to minimize the cost to customers.

The following sections describe:

- an overview of the asset management objectives applicable to replacement and renewal, and strategies to achieve those objectives
- how we manage our asset fleets
- the factors that influence our asset management strategy
- our approach to forecasting and drivers for asset replacements
- a summary of the major investments identified to maintain network performance between 2023 and 2033

12.1 Renewals objectives and strategy

12.1.1 ASSET MANAGEMENT OBJECTIVES

The asset management objectives that are addressed through the replacement and renewal programme of works and investments are set out in the table below.

FOCUS AREA	OBJECTIVES
Safety, Environment and Network Security	• Comply with relevant safety and environmental legislation, regulation and planning requirements. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and Stakeholders	• Enable customers' future energy and technology choices.
Network Performance & Operations	• Utilise clear business case processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with security of supply standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings.
Future Energy Network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc – operations: transition to distribution system operator model and whole of system planning • Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Improve our visibility of, and ability to control, the LV network including management of the information required.

TABLE 12-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

12.1.2 STRATEGIES TO ACHIEVE THE OBJECTIVES

To meet the asset management objectives, the following strategies are employed by Vector. As electricity networks are complex interconnected systems, each strategy addresses multiple objectives.

12.1.2.1 COMPLY WITH RELEVANT REGULATIONS

Vector will comply with the relevant regulatory obligations, legislative requirements such as the Electricity Safety Regulations and industry standards. The most relevant to network integrity, growth and security are compliance with the Security of Supply Standards, achieving and maintaining compliance with the DPP3 Quality Standards and complying with the Power Quality requirements.

By modelling the condition of our assets, we identify where assets are likely to fail and plan our remedial actions to prioritise the assets with highest criticality through to lowest criticality, hence managing network risk, and ensuring resilience and compliance with regulations.

12.1.2.2 ASSET INFORMATION AND INSIGHTS STRATEGY

Vector has established the Information and Insights Strategy, which is tightly coupled with the Digital Strategy, to focus on improving asset data and condition information to enable advanced analytics. Initiatives under this strategy have included investing in new systems to improve the quality and accuracy of asset data, such as SAP PM, and establishing KPIs for our Field Service Providers (FSP) that focus on asset data capture, completeness and quality.

12.1.2.3 RISK BASED ASSET CONDITION FORECASTING METHODS

Vector applies a risk-based approach to forecasting asset condition, and therefore the expected asset volumes and expenditure required for asset replacement. The value and criticality of the asset type determines the complexity of the modelling implemented so that the effort is appropriate for the risk posed to the network. Asset obsolescence, vendor support and/or availability of spare parts are included in the condition assessment of asset types. For example, high value assets such as switchboards are forecasted using condition-based risk models, whereas low value and low criticality assets such as LV distribution equipment, are forecast using historical trend models.

12.1.2.4 MAINTAINING NETWORK SAFETY

Safety of the public and staff is of the highest importance to Vector. Where an asset is identified to pose a risk to safety, we will prioritise remedial actions to remove the risk. Vector is required to operate its network in compliance with NZS7901 which details safety management systems for public safety.

Where an asset is identified to pose a risk to safety, Vector will prioritise remedial actions to remove the risk.

12.1.2.5 MANAGING ASSETS TO ENSURE LEAST COST ACROSS THE LIFE CYCLE

At each point in an asset's life cycle, Vector will take the appropriate action to ensure the least cost of owning the asset across its life cycle. Actions may include replacement/retirement if the asset is no longer needed, refurbishment/life extension, or maintenance.

Our approach is to identify possible options to resolve the constraint, undertake a cost and benefit analysis for asset replacements of each solution, and to select the solution which has the best benefit-cost ratio. The options analysis considers capital and operational costs, safety, environmental impacts, risks and opportunities from the whole of asset life perspective. For some low value asset classes, a run to failure approach with reactive replacement is applied where deemed more efficient.

12.2 Forecasting methods

The purpose of forecasting assets renewals is to ensure that an appropriate level of capital and resources are available for Vector to manage network risk at a fleet level and align with our wider Asset Management Objectives. Vector uses a number of different methods to forecast asset renewals needed on its network. The type of forecasting method used is dependent on the asset value, asset criticality, population size, renewal drivers and robustness of available information associated with the asset class.

For high value assets such as power transformers, where inspection and testing provide robust condition information, predictive modelling is undertaken to understand when individual assets are at the end of their serviceable life. For low value high volume assets that are less critical to network operations, such as air-break-switches, the forecasting is done at a portfolio level to identify the expenditure required for the asset fleet while actual replacements are identified based on field inspections. The forecasting methods applied by Vector are described below.

12.2.1 RISK BASED MANAGEMENT

Vector has adopted the use of Condition-Based Asset Risk Management (CBARM) to model the condition of selected asset classes from a fleet perspective. This approach is based on the methodology published by the UK regulator Ofgem [1] (Office of Gas and Electricity Markets) and considers asset criticality, asset health data, deterioration rates, and probability of equipment failure. The outcome of this modelling provides a fleet-wide overview of the asset health risk of a particular asset class. It also allows various intervention strategies to be tested by providing a forecast of the asset risk profile in the future. By comparing different intervention strategies Vector is able to assess the scale of replacement required to efficiently manage network risk.

The asset data used as inputs to the models are directly retrieved from SAP PM thereby enabling each model to be updated with the latest information from the field. Vector's focus on improving its asset health information is complementary to the continued improvement in the accuracy of its CBARM models."

In the context of this AMP the output of our CBARM models have been defined using the following risk categories:

- **R1: Minimal risk** – Assets are generally in good condition. Continue to review and monitor using current asset maintenance standards.
- **R2: Moderate risk** – Assets are showing signs of deterioration. Where issues have been identified, these can be addressed through corrective maintenance to ensure the assets remain serviceable.
- **R3: High risk** – Assets have defects that have the potential to cause failure. Remedial planning and specific actions need to be identified and executed.

[1] DNO Common Network Asset Indices Methodology

- **R4: Maximum risk** – Assets are in a poor condition with a heightened risk of failure. Requires immediate remedial actions.

12.2.2 CONDITION BASED ASSESSMENT

In instances where asset criticality information is not available, the asset fleet condition is based on various health indicators such as age, type, known defects and results of routine testing. This differs from CBARM as it produces a condition score rather than risk score, that is the criticality of the asset is not assessed. An example of this the power transformer asset class where the condition score is based on the results of tests on the oil and insulation in addition to age and type, to arrive at a combined condition score. The asset fleet health indicators are described using the criteria below:

- **H1: Negligible risk of failure** – Assets are generally in good condition. Continue to review and monitor using current asset maintenance standards.
- **H2: Moderate risk of failure** – Assets are showing signs of deterioration. Where issues have been identified, these can be addressed through corrective maintenance to ensure the assets remain serviceable.
- **H3: Increasing risk of failure** – Assets have defects that have the potential to cause failure. Remedial planning and specific actions need to be identified and executed.
- **H4: Material risk of failure** – Assets are in a poor condition with a heighted risk of failure. Requires immediate remedial actions.

This assessment approach is compared against historical records to validate any anomalies in modelling outputs.

12.2.3 AGE AND TYPE

For some asset classes it is appropriate to use deterministic factors such as age and type information to predict asset replacement needs. In particular, where it is not efficient or possible to gather sufficient condition information to assess the health of individual assets or develop a CBARM model.

An example is digital devices, such as modern protection relays, which are generally managed to a specific age as it is not possible to assess the condition of the integrated circuits and/or software and firmware upgrades are not available anymore.

12.2.4 HISTORICAL TRENDS

In asset classes where there is insufficient asset information available to support the use of the methods above, the number of assets replaced on an annual basis can be predicted by referring to historical trends. The historical trend rates can also be extrapolated or adjusted to account for changes in age across the fleet. This is typically applied to high volume, low value and low criticality asset types.

A high-level summary of renewal forecasting methods and renewal drives by asset class is provided below in Table 12-2:

FLEET	RENEWAL DRIVER	PRIMARY FORECASTING METHODS
Subtransmission switchgear	Obsolescence, condition, age, safety, reliability	CBARM and Condition based assessment
Power transformers	Obsolescence, condition, age, safety, reliability	CBARM and Condition based assessment
Underground cables	Condition, age, safety, reliability, environmental	CBARM, Historical for LV
Overhead lines	Condition, age, safety, reliability, environmental	CBARM and Condition based assessment
Support structures	Condition, age, safety	Condition based assessment
MV Distribution equipment	Condition, age, safety, reliability	CBARM
Distribution transformer	Condition, age, safety, reliability, environmental	CBARM
LV Distribution equipment	Obsolescence, condition, age, safety, reliability	Historical
Protection and controls	Obsolescence, age, availability of spares, functionality	Type and age
Auxiliary systems	Obsolescence, age, reliability	Type and age, Historical
Generation and energy systems	Condition, age	Historical
Infrastructure and facilities	Condition, safety	Historical

TABLE 12-2: RENEWAL DRIVERS AND FORECASTING METHODS

12.3 Primary switchgear

The purpose of primary switchgear is to provide protection of the network and primary assets such as underground cables and overhead lines, as well as a point of control and isolation of primary circuits.

Primary switchgear is used to provide a means to safely disconnect a faulted section of the network and to provide a point of control or isolation needed for network control or planned maintenance activities.

This Section describes our primary switchgear fleet and provides a summary of our associated asset management practices. The primary switchgear fleet consists of the following three subcategories:

- Indoor and outdoor 110 kV switchgear
- Indoor 33 kV, 22 kV and 11 kV switchgear
- Outdoor 33 kV switchgear

12.3.1 110 KV SUBTRANSMISSION SWITCHGEAR

12.3.1.1 FLEET OVERVIEW

Three sites on Vector's network house 110 kV switchgear. Liverpool and Hobson Zone Substations both have indoor GIS switchboards and Lichfield GXP has two outdoor circuit breakers. All of Vector's 110 kV switchgear are SF_6 insulated and use SF_6 puffer circuit breaking technology.

12.3.1.2 POPULATION AND AGE

The two outdoor 110 kV GIS circuit breakers at Lichfield GXP are 27 years old. The 110 kV GIS switchboards at Liverpool and Hobson zone substations are 25 and 11 years old, respectively. The Liverpool switchboard was extended in 2021 with the installation of three new circuit breaker bays

12.3.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Vector's indoor GIS assets have been performing well with no notable failures since commissioning. Although not an issue at this time as more than half of the fleet is under 11 years old, assets of this type are vulnerable to obsolescence as more modern designs become available and the original equipment manufacturer (OEM) no longer provides support or can make readily available parts. To mitigate this risk, Vector has secured strategic spares and vendor support for these assets.

The circuit breaker operating drives on the GIS switchboard at Liverpool substation are approaching the timeframe for mid-life refurbishment and upgrade. To mitigate the increasing risk of drive-mechanism failure presented by the existing hydraulic system, Vector has engaged in a program of complete hydraulic systems renewal with extended monitoring and control functionality. This major 20-year mid-life refit program commenced in FY22 with the purchase of all the long lead items and completion is forecast in FY23.

There are known issues associated with the SF_6 gas seals on the outdoor circuit breakers installed at Lichfield GXP (a spare pole is held on site) as well as the ability to maintain a supply of serviceable spares. Because of their condition, contribution to Vector groups carbon emissions, and the availability of spare parts, these circuit breakers are scheduled for replacement in 2028 (refer to Appendix 12 for details).

12.3.1.4 CONDITION AND HEALTH

Provided there are no major failures, indoor GIS switchboards technically have no end of life if proper maintenance is undertaken and there is a supply of spares. The Merlin Gerin type D-TH7 switchboard installed at Liverpool zone substation is no longer in production but is still supported by the OEM factory in Grenoble France (MasterGrid) for parts and service. Some of its components are vulnerable to age related deterioration such as gaskets, "O" rings and polycarbonate materials which have been historically difficult to acquire. Vector has recently repaired known SF_6 leaks with seal and component renewals and has further procured a contingent of spare parts to minimise any future repair time. A project to install gas loss trending equipment to monitor the leak rate of any compartment has also been completed which will act as an early warning system to investigate any future leaks more expeditiously.

As the Lichfield 110 kV circuit breakers are located outdoors, they are prone to the typical issues associated with air insulated outdoor switchgear such as corrosion, pollution, or animal interference. These circuit breakers have performed in line with expectations, but their age and risk of obsolescence mean that they are approaching end of life.

12.3.1.5 MANAGEMENT STRATEGY

Subtransmission GIS switchgear is procured to align with site specific functional and performance requirements.

The maintenance for the 110 kV indoor GIS is detailed in Vector's maintenance standard ESM102 and the outdoor breakers at Lichfield zone substation are covered under Vector's maintenance standard ESM103. Planned maintenance activities consist of inspection and testing with specialist work contracted to the OEM. Routine inspections are undertaken by Vector's FSPs every two months. Specific OEM service works are conducted at a frequency of between one and eight years depending on the level of service and make and model of the switchgear as determined by the OEM. The replacement of this asset class is driven primarily by obsolescence, lack of vendor support or availability of spare parts and is conducted on a proactive basis.

The outdoor circuit breakers installed at Lichfield zone substation are planned to be replaced for legacy, reliability and economic reasons.

12.3.2 INDOOR PRIMARY SWITCHGEAR

12.3.2.1 FLEET OVERVIEW

Indoor primary switchgear on Vector's network operates at 11 kV, 22 kV or 33 kV depending on the topology of the network. The 33 and 22 kV switchgear are used for subtransmission and 22 kV is used for distribution in certain areas of higher density load. Indoor switchgear comprises modular panels containing integrated devices such as circuit breakers, disconnectors, earth switches, instrument transformers and protection relays. A series of modular panels connected together makes up a switchboard and is housed in a purpose-built building with temperature and humidity control. This switchgear is generally more reliable than its outdoor equivalents because it does not incur as many issues associated with corrosion, pollution and other environmental factors.

The indoor switchgear on Vector's network includes both conventional and fixed pattern types. The conventional switchgear fleet uses oil, vacuum or SF_6 for its interrupter mediums whilst modern fixed pattern switchgear uses vacuum interrupter technology only. The composition of this fleet according to build type, interrupter type and voltage level is provided in Table 12-3 below.

TYPE	33 KV FIXED PATTERN	33 KV CONVENTIONAL	22 KV FIXED PATTERN	22 KV CONVENTIONAL	11 KV FIXED PATTERN	11 KV CONVENTIONAL
Oil						350
Vacuum	176	4	93		586	351
SF_6		18		29		133

TABLE 12-3: INDOOR SWITCHGEAR

12.3.2.2 POPULATION AND AGE

The population and age profile for both the conventional and fixed pattern indoor switchgear types is shown below in Figure 12-1 for each voltage level.

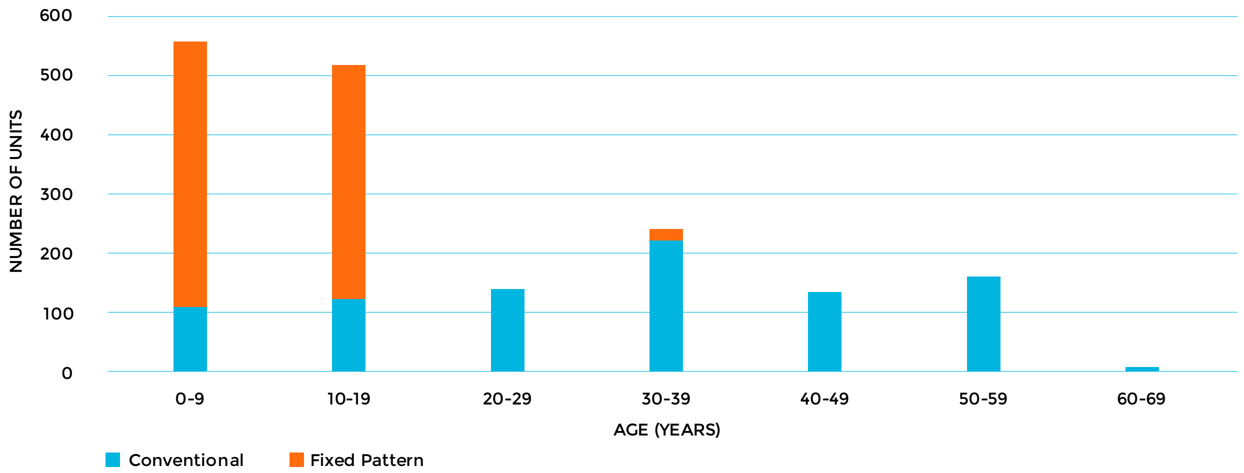


FIGURE 12.1: INDOOR SWITCHGEAR FLEET AGE PROFILE

12.3.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Indoor switchgear of conventional design has several known failure modes including mechanical failures, insulation breakdown and secondary circuit malfunctions. The issues identified for indoor switchgear of fixed pattern design are relatively minor in comparison to conventional design. Fixed pattern switchgear has generally proven to be reliable and performed well with no major incidents recorded. Minor incidents involving these assets are usually attributed to improper cable installation or termination rather than defective equipment.

12.3.2.4 CONDITION AND HEALTH

Vector has recently developed a CBARM model to assist to inform the replacement programme for indoor switchboards. This model is based on age, condition and criticality. The present (RY23) risk level for the indoor switchboard fleet is shown below in in Figure 12-2.

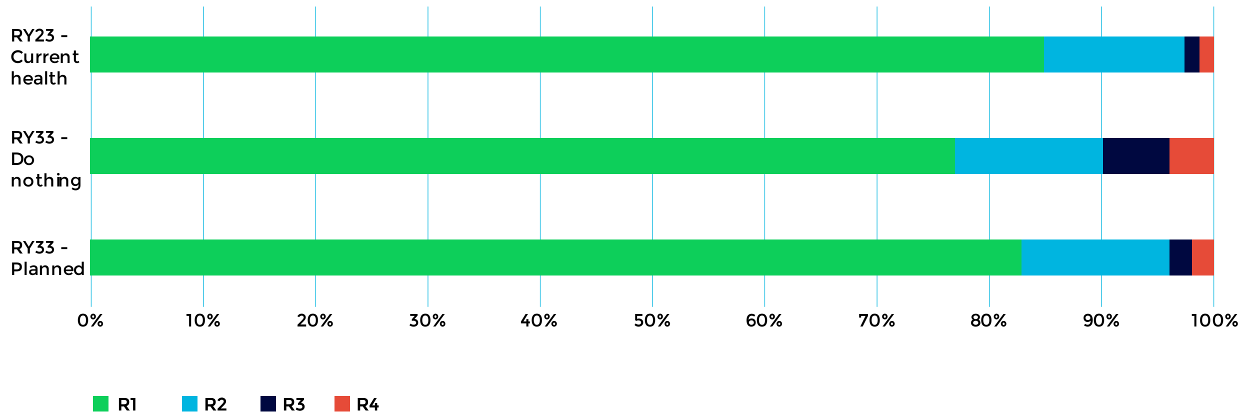


FIGURE 12.2: INDOOR SWITCHBOARD FLEET RISK PROFILE

This indicates that the indoor switchboard fleet is in good condition and Vector's investment programme will maintain the risk profile at approximately present levels. Full details of this programme are provided in Section 12 Appendix.

12.3.2.5 MANAGEMENT STRATEGY

The management strategy for indoor switchboards is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.3.2.6 DESIGN AND CONSTRUCT

Vector has adopted fixed pattern switchgear as a standard given its safety, reliability and performance benefits as well as reduced maintenance needs over conventional switchgear. As such, conventional switchgear is procured by exception and where it is an economic and safe solution. Examples of this include extensions to existing switchgear and oil to vacuum breaker conversions. Generally, fixed pattern switchgear is used for all new installations and is procured using Vector's specification ENS-0005. Conventional switchgear is procured based on specific site performance and functional requirements.

12.3.2.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM103 for conventional switchgear apparatus is a culmination of best practice as per AS/NZ 2467 standard and manufacturer specific maintenance regimes. In addition, Vector has recently purchased a magnetron atmospheric condition tester to better determine the condition and serviceability for vacuum circuit breakers (where it is physically possible to be used). Vector has a separate maintenance standard ESM101 specifically for fixed pattern switchgear.

Typical planned maintenance activities are shown below in Table 12-4.

ACTIVITY DETAIL	Visual inspections	Thermovision inspections	Partial discharge testing	Kelman testing (dissolved gas analysis)
FREQUENCY	2 Months	1 Year	2 Years	2 Years

TABLE 12-4: PLANNED MAINTENANCE ACTIVITIES FOR INDOOR AND OUTDOOR SWITCHGEAR

In addition, specific OEM service works are conducted at a frequency of between two and sixteen years depending on the level of service, make and model of the switchgear as recommended by the vendor. Investigations, programs of repair, inspection and modifications have been initiated where systemic issues are identified. For example, the cable terminations on Schneider switchgear incomer CBs were changed from socket type outer cone terminations to inner cone terminations to reduce the risk of torsional forces on 33 kV bushings leading to premature failure.

12.3.3 OUTDOOR PRIMARY SWITCHGEAR

12.3.3.1 FLEET OVERVIEW

Conventional outdoor switchgear is a general classification for 33 kV outdoor circuit breakers [1], associated bus works, support structures, disconnectors and instrumentation. Their deployment is limited to the Northern region and this class of switchgear is used exclusively for subtransmission in the Vector network.

Vector's outdoor 33 kV switchgear fleet includes both conventional and GIS types as shown in Table 12-5.

TYPE	33 KV GIS – OUTDOOR	33 KV CONVENTIONAL - OUTDOOR
Oil		59
Vacuum	20	10
SF_6		3

TABLE 12-5: OUTDOOR SWITCHGEAR

[1] Note that 'outdoor circuit breakers' excludes the 110 kV circuit breakers at Lichfield GXP

12.3.3.2 POPULATION AND AGE

Vector has 92 outdoor circuit breakers in service across its network. The population and age profile for these outdoor circuit breakers is presented below in Figure 12-3.

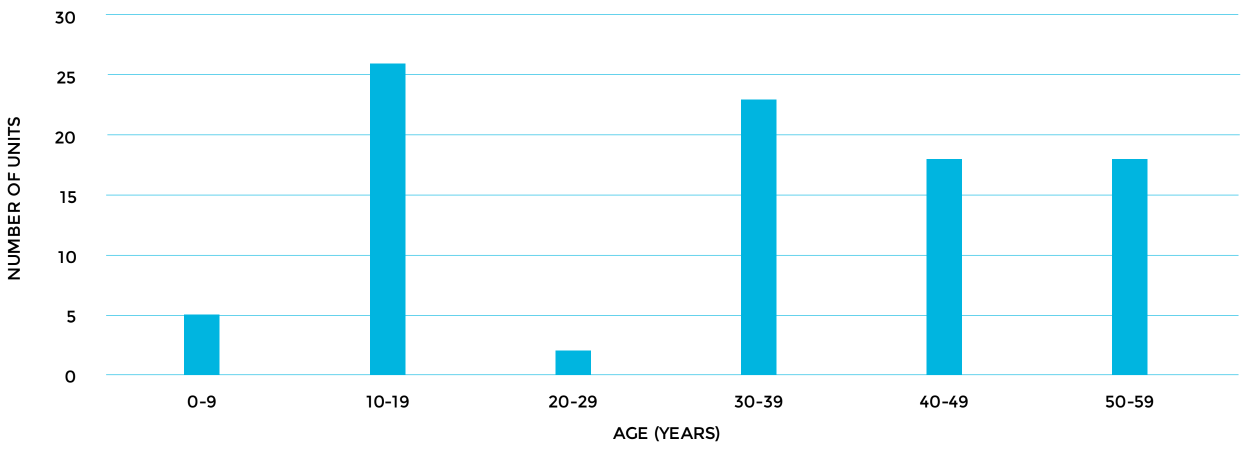


FIGURE 12.3: OUTDOOR 33 KV SWITCHGEAR FLEET AGE PROFILE

12.3.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

In 2013, a Vector owned 33 kV oil-filled circuit breaker failed at Transpower's Hepburn Road GXP resulting in collateral equipment damage in the switchyard and a prolonged outage. This is an inherent risk of all outdoor switchyards containing oil-filled circuit breakers with porcelain bushings, which have the potential to fail catastrophically, resulting in damage to surrounding equipment. The risk of failure for these type of circuits breakers increases as they get older.

12.3.3.4 CONDITION AND HEALTH

This asset class is aging with the average age being 31 years. The reliable working age for this asset type is 40 years and therefore approximately 53% of the fleet requires remediation or replacement within the next ten years. There have been two failures of this asset type, namely at Milford zone substation in 2007 and as stated above, at Hepburn GXP in 2013. In both cases, complete replacements were undertaken.

12.3.3.5 MANAGEMENT STRATEGY

Typical planned maintenance activities are shown in Table 12-4. Vector is managing the risk of failure of outdoor circuit breakers by progressively replacing those circuit breakers that have been identified to pose a risk on the network with indoor fixed pattern type. However, there are instances where a complete conversion to indoor fixed pattern switchgear is not economical in which case new SF_6 outdoor circuit breakers will be utilised. Vector's specification ENS0106 covers the requirements for new outdoor circuit breakers should they be required as one-off replacements or extension projects should strategic stock be unavailable.

There is no planned like-for-like asset replacement programme for individual outdoor circuit breakers with the intention being to replace them with modern indoor fixed pattern switchgear. This equipment has improved safety, spatial, maintenance and economic benefits and eliminates the risk of catastrophic failures of porcelain outdoor switchgear bushings.

In addition to Vector's internal replacement program of this type, Vector has also worked with Transpower to replace similar 33 kV outdoor circuit breakers at GXPs under a so-called outdoor to indoor conversion programme colloquially known as the 'ODID' programme. This programme has made good progress with only two GXPs remaining.

12.3.4 REPLACE, RENEW AND DISPOSE

Renewal and refurbishment of primary switchgear assets is undertaken to ensure continued reliable and safe operation of the assets well into the future. Our switchgear assets need to be considered in light of the cost of continued maintenance, obsolescence, vendor support and the availability of spares. The afore mentioned as well as the asset health and criticality drives our switchgear replacement programme.

In addition to the above, environmental factors and climate change such as a risk of flooding as an example, will also drive the need and timing for replacement of primary switchgear out of harm's way. The programme of works for primary switchgear replacement consists of either a complete replacement of switchgear, or partial replacement or retrofit of oil circuit breakers with vacuum circuit breakers as the case may require.

When primary switchgear is replaced, components are carefully selected and retained to serve as strategic spares for similar equipment that remain in service. Carcasses are then scrapped as per Vector's contractual agreements with scrap metal companies.

12.3.5 FORECAST SPEND

The forecast capex graph shown in Figure 12-4 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for primary switchgear is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.

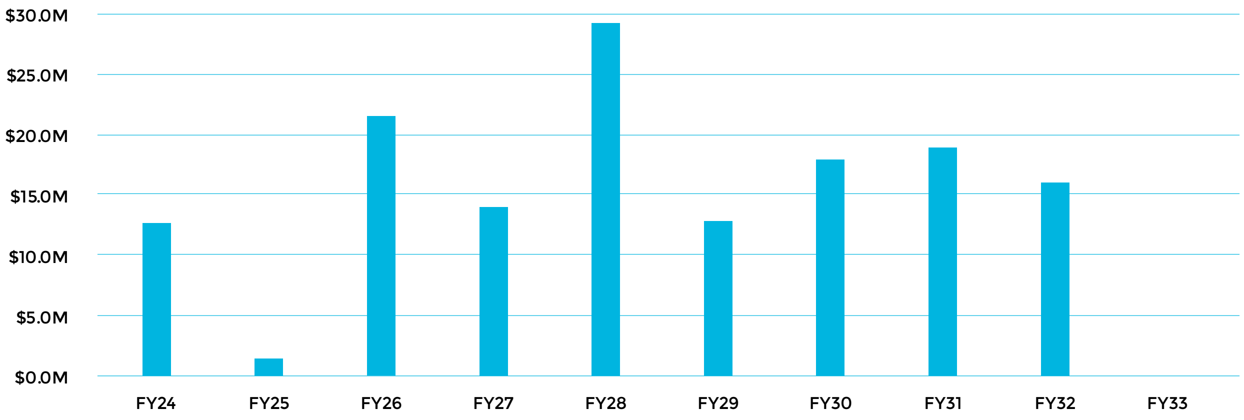


FIGURE 12.4: FORECAST CAPEX – PRIMARY SWITCHGEAR

12.4 Power transformers

This Section describes our Power Transformer fleet and provides a summary of our associated asset management practices within the following three subcategories:

- Power Transformers
- Power Transformer Tap Changers
- Power Transformer Ancillaries

12.4.1 POWER TRANSFORMERS

Power transformers are static devices that are used to transform electrical energy from a higher voltage to a lower voltage. They are critical and capital-intensive assets for utilities. Power transformers come in various sizes, phase arrangements and voltages. Performance of the power transformer is critical to maintaining supply to customers.

Power transformers are robust with very good reliability, requiring relatively low maintenance. However, the on-load tap changers are prone to wear and tear which can lead to premature failure if not monitored and not regularly maintained. The internal health of a transformer is not easily observed and therefore it is highly important for transformers to be regularly monitored and tested to ensure the overall health of the asset is within acceptable parameters and limits. Failures of power transformers are rare, but if they occur, they are often sudden, can be catastrophic and can cause considerable collateral damage to other equipment, lost revenue, extended network outages, and in rare instances injury or death to persons.

12.4.1.1 POPULATION AND AGE

Vector currently has 223 power transformers in service ranging from 5 MVA to 80 MVA. They take supply from the Transpower network at 110 kV, 33 kV and 22 kV to step the voltage down to 22 kV or 11 kV for network distribution. The transformer fleet is composed of 21 different manufacturers encompassing 37 different models. Since the year 2000, Vector has standardised on a small number of manufacturers and power transformer models which has reduced the type and number of spare parts required.

Table 12-6 provides a summary of the population of our power transformers by voltage category. Most of our power transformers (approximately 70%) are rated 33/11 kV.

CATEGORY	110/11 KV TRANSFORMER	110/22/11 KV TRANSFORMER	110/33 KV TRANSFORMER	110/22 KV TRANSFORMER	33/22 KV TRANSFORMER	33/11 KV TRANSFORMER	22/11 KV TRANSFORMER
Population	2	2	5	10	1	160	43

TABLE 12-6: POWER TRANSFORMER POPULATION

Figure 12-5 illustrates the age profile of our power transformer fleet. The average age of our power transformers is 32 years. Forty-five power transformers are 50 years and older with the oldest being 63 years of age.

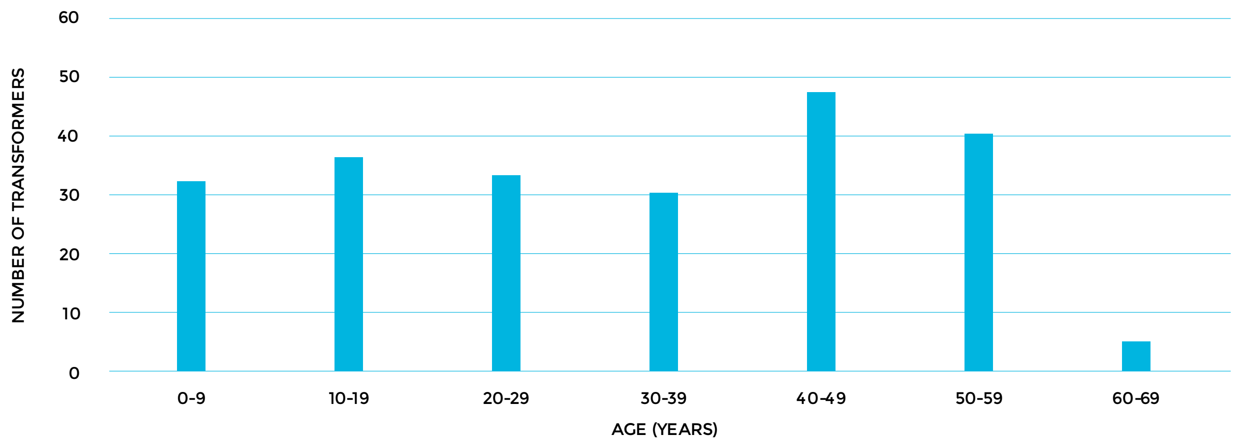


FIGURE 12.5: POWER TRANSFORMER FLEET AGE PROFILE

12.4.1.2 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector relies on Dissolved Gas Analysis (DGA) of the insulating oil in the form of Transformer Condition Assessment (TCA) of the main tank and Tap Changer Activity Signature Analysis (TASA) for its tap changers. This type of oil testing identifies the presence of different gases and by-products of internal insulation degradation and trending over time, allowing Vector to trend and determine the health of the internal condition of the power transformer fleet.

In addition to the TCA, power transformers are monitored using Reg-DA voltage regulating relays and protection relays. These protection relays monitor inputs from current transformers, instrument transformers, temperature sensors, oil level sensors and Buchholz devices (which detect internal faults resulting in rapid gas accumulation and surges inside transformers). Incipient faults trigger alarms via SCADA which then elicits a response by field crews to undertake detailed investigations.

Over the last 20 years, there have been very few power transformer faults resulting in complete loss or long-term outages. These faults were mainly due to close in through faults or tap changer failure. in most cases the power transformers were able to be repaired. However, in rare cases, the power transformer had to be replaced: details of power transformer failures can be found in Vector's asset strategy for this header class. Overall, the performance of Vector's transformer fleet has been very good.

12.4.1.3 CONDITION AND HEALTH

Vector is actively monitoring the health and condition of the power transformer fleet to ensure we get the optimum life from this fleet. We carefully manage our power transformers so that they are not subject to excessive or prolonged high electrical loading and we ensure they undergo regular testing in accordance with our maintenance regime.

Vector utilises a VIA analytics model to provide a fleet-wide overview of the condition of its power transformers. Using the available asset health data as input, the model is able to estimate the current health of the transformer fleet, as well as forecast the future health levels in response to different modelling scenarios. The output of this model is used to inform which unit(s) should be refurbished or replaced. Vector's strategy is to progressively replace the population of power transformers that have the worst asset health and are the most likely to suffer major failures.

The present (RY23) condition level for the power transformer fleet is shown in Figure 12-6.

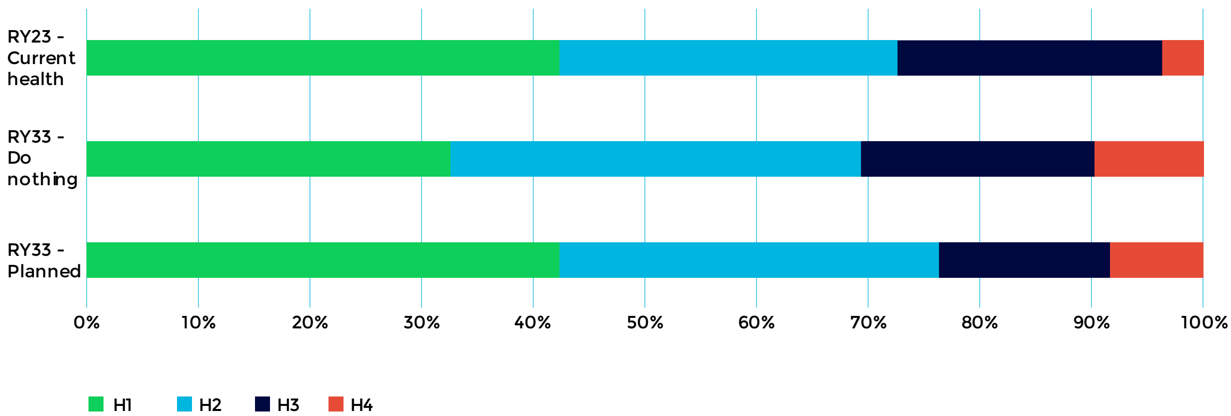


FIGURE 12.6: POWER TRANSFORMER FLEET CONDITION PROFILE

This indicates that Vector's power transformer fleet is in good condition and approximately 10% of the fleet will approach end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet is appropriately managed.

12.4.1.4 MANAGEMENT STRATEGY

The optimal life cycle investment considers the balance between asset renewal requiring capital expenditure and the combination of reactive, preventive and corrective operational expenditure. The strategies for each of the stages of a transformer lifecycle have been established to address the fleet condition and performance.

Vector has agreed with Transpower to add an additional 220/33 kV interconnecting grid transformer to supplement the existing T7 interconnecting grid transformer at Transpower's Wairau GXP adjacent to Vector's Wairau bulk supply substation. The Vector owned 110/33 kV transformers at Wairau zone substation will be retired in a staged decommissioning program after the second 220/33 kV grid transformer is commissioned into service.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.4.1.5 DESIGN AND CONSTRUCT

Vector has two specification standards for new power transformers:

ENS-0120 - Specification for two winding power transformers (33 kV/11 kV); and

ENS-0124 – Specification for 110 kV/22 kV two-winding power transformers

These two Vector standards refer to IEC standards and form the basis under which all new power transformers are purchased. Since the year 2000, Vector has standardised its fleet to 15 MVA and 20 MVA transformers to allow efficient strategic spares management and optimise maintenance tasks. Recently Vector has introduced 28 MVA rated transformers as an option to accommodate customer connections requiring more capacity.

12.4.1.6 OPERATE AND MAINTAIN

Power transformers have very long in service life expectations and can operate at full load continuously. However, continuous use at full rating will result in the insulation life of the paper being exhausted and failure will become imminent at around 25 years. However, Vector, like most utilities worldwide, designs its network with N-1 contingency and as a result the loading on our power transformers is rarely greater than 50% of its nameplate rating for the majority of its operating life. At this level of loading, we can expect service lives well in excess of 50 years.

The insulation of power transformers comprises mineral oil, paper and pressboard that has a finite life even under ideal operating conditions. Aging of the paper insulation depends primarily on the operating temperature of the oil and the time in operation at high oil temperatures. Moisture and the presence of oxygen are other factors that will accelerate the ageing of the insulation. Another factor in the life expectancy of a power transformer is the number of downstream faults to which a transformer has been subjected. High magnitude through faults may cause winding and core deformation that will lead to unintentional short-circuits across the insulation, of which a high percentage are irreparable. Depending on the condition of power transformer, mid-life refurbishment is an option to extend the life of a transformer.

Oil tests are conducted on an annual basis, supplemented with TCA and Furan analysis every third year. This program of testing was implemented approximately twenty years ago as a means of lowering operating cost and reducing faults caused by incorrect maintenance on tap changers using time and operations-based intervals.

Vector's maintenance standard ESM201 details the planned, corrective and reactive maintenance requirements for its power transformer fleet. The planned maintenance regime for our power transformer assets is summarised below in Table 12-7.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection of power transformer	2 Months
Thermovision Inspection	Thermovision Inspection of power transformer	1 Year
Partial Discharge Inspection	Partial Discharge Inspection of power transformer	2 Years
Service	Service on tap changer	5 years
Testing	Testing of oil in the power transformer tap changer	1 Year
Testing	Testing of oil in the power transformer tap changer (Vacu-tap)	1 Year
Testing	Testing of oil in the power transformer tank	1 Year
Testing	Testing of oil in the power transformer tank – Furan	3 Years
Testing	Testing of Power transformer protection	4 Years
Testing	Benchmark electrical tests	5 Years

TABLE 12-7: PLANNED MAINTENANCE ACTIVITIES FOR POWER TRANSFORMERS

Until recently, maintenance activities on power transformers were solely triggered from the results of oil analytics. However, an increase in unexpected power transformer failures and faults prompted Vector to introduce a time-based electrical benchmark testing regime to supplement oil testing analytics. Recent electrical baseline tests have identified issues that would not have otherwise been picked up with oil testing alone.

Corrective maintenance is a task carried out to further diagnose or restore a network asset to its serviceable condition and involves further testing, repairing or replacement of parts to ensure that the unit is functioning effectively. Vector's maintenance standard ESM201, Section 4 details the requirements of specific corrective maintenance activities for power transformers.

Reactive maintenance work for power transformers involves returning a power transformer to service, usually after an unplanned outage due to an unforeseen event such as close-in through faults. For every unplanned outage, we undertake post event root cause analysis to ensure that any valuable information as a result of the fault is captured and data is available to identify any trends.

A Failure Mode Effect Analysis (FMEA) register has been created for all power transformers to consider the design, procurement, construction, testing and commissioning, operations and maintenance, and decommissioning. Outputs from the FMEA will be used to further develop the Transformer Risk Ranking tool to provide greater population risk analysis, improved maintenance and inspection regimes and better prioritised asset replacement programs of work.

12.4.2 POWER TRANSFORMER TAP CHANGERS

The purpose of a tap changer is to regulate the output voltage of a transformer so that it can be maintained within the required voltage range. Tap changers have preconfigured 'steps' with typical changes to the output voltage of 1.25% per step to +5% and down to -15%. Tap changers can be fitted to either the primary (HV) or secondary (LV) winding but the majority are fitted to taps on the HV winding due to the lower current and easy access to the outer HV winding.

12.4.2.1 POPULATION AND AGE

Power transformers for Vector's network are procured complete with a tap changer. Tap changers are intended to match the entire life of a power transformer subject to good maintenance practices. It is rare that a tap changer is replaced in its entirety and can generally be considered as fit for life. As such, asset health modelling is focused on the power transformer as described in the previous section instead of considering tap changers separately.

There are two types of tap changers in use: on and off load. Most of Vector's power transformers are equipped with oil type on-load type tap changers because they can be operated while the transformer is energised. Since 2009, Vector has procured power transformers with vacuum interrupter type on-load tap changers. The off-load types require the transformer to be de-energised and isolated so are only used where automatic voltage regulation is not required. Only two of Vector's power transformers are fitted with off-load tap changers.

Currently, Vector has tap changers in service from eight different manufacturers with Ferranti, Fuller and Reinhausen being the most prevalent. Since 2000, Vector has standardised its fleet to use only Reinhausen tap changers.

12.4.2.2 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Due to age and uncommon types of tap changers used on some of the transformers, there is a risk of obsolescence and unavailability of spare parts. Vector has partnered with local manufacturers to custom manufacture parts as needed.

Secondary system components such as tap-changer drive/control mechanisms are complex and prone to faults as the equipment ages. This type of failure does not often result in a catastrophic failure but can contribute to power quality issues.

12.4.2.3 CONDITION AND HEALTH

Vector uses the results of TASA (Tap Change Activity Signature Analysis) oil tests results to trigger maintenance activities. TASA oil tests assume a certain number of operations over the entire range of the tap changer positions, rather than the actual range. Because of Vectors excellent voltage stability, tap changers seldom transition more than three taps either side of the nominal position. With a similar number of tap change operations, oil test results from the tap changer cycling through all 17 tap positions vs. a tap changer cycling through only six positions would show similar results, but the contacts of the latter would show significantly less deterioration.

While TASA oil tests have proven to reduce costs as compared to traditional time-based methods, they are not perfect. Vector has recently experienced issues with tap changers not picked up by this test method. To overcome this issue, a new time and operations-based inspection and maintenance activity has been introduced to the maintenance programme on an initial five year basis. This new activity will coincide with the new time-based electrical benchmark testing activity being introduced for power transformers.

12.4.3 POWER TRANSFORMER ANCILLARIES

In addition to the main tank and tap changer, there are small but important components fitted to a power transformer. These ancillary components include:

- Bushings - Every power transformer is fitted with LV and HV bushings. Nearly all Vector power transformers are fitted with solid porcelain bushings. Older outdoor power transformers are fitted with solid porcelain oil filled type bushings. These are reliable having no systemic issues other than periodic leaks of a gasket, which are usually minor in nature and repairable.
- Protection Equipment - Protection, control and monitoring of power transformer comprises either legacy analogue, solid state or fully digital systems. The preferred digital platform is the REG-DA (A-Eberle) system for voltage control and transformer monitoring.
- Neutral Earthing - Neutral earthing resistors act to reduce the fault current during phase to earth faults. They are effective to reduce damage to network equipment and require little to no maintenance and are co-located with the power transformer.
- Cooling Systems - There are two systems used on Vector's transformers; bulk oil cooling and heat exchanger systems. The oil radiator system is by far the most common in use and is also an uncomplicated system. The heat exchanger system relies on the continuous operation of pumps and is rarely used due to its complexity.
- Oil Preservation - All of Vector's power transformers are either of a free breathing or atmoseal (bladder) type preservation systems. The free breathing type are not sealed from the atmosphere. As the unit heats and cools through normal operation, the changes in the oil volume are taken up in the headspace of the conservator tank.

12.4.3.1 CONDITION AND HEALTH

Transformer ancillaries are almost always acquired at the same time as the power transformer and are covered by the same specifications. Transformer ancillaries are expected to last as long as the power transformer. Vector maintains a stock of spare parts and ensures contractor capabilities to carryout timely repairs.

12.4.3.2 MANAGEMENT STRATEGY

Maintenance of ancillary components is carried out during periodic inspections or by test regimes as indicated by Vector's maintenance standards.

If required, some component parts are replaced or repaired as necessary under corrective works. However, the ancillary components are generally replaced when the power transformer is replaced.

12.4.4 REPLACE, RENEW AND DISPOSE

The key drivers for replacement are asset health and criticality to ensure the continued reliability of zone substations. Operationally, most of Vector's fleet of power transformers have been loaded well below their design rating thus ensuring oil and winding temperatures have been kept low through a majority of their operating life thus prolonging the life of the paper (cellulose) insulation. This often enables 30–40 year old units to have what is commonly called a 'midlife refurbishment' in which the transformer is taken off-site and is completely stripped down, dried out and all badly worn parts replaced before being re-assembled and taken back to site.

The refurbishment is undertaken in accordance with Vector's standard ENS-0164 with the objective to extend the life of the transformer by 25 years. Candidates for refurbishing are reviewed on a case-by-case basis, triggered by condition, criticality and future value to the network. The economics of the option to refurbish vs replacement are also considered.

The availability of spare parts, especially for tap changers, will impact our decision on whether to refurbish or to replace a power transformer. Notwithstanding our maintenance and testing regime, the asset health of our oldest power transformers has now reached a stage where 'midlife refurbishment' is unlikely to be an economic option.

Power transformers that require replacement are scrapped but parts will be salvaged and placed in strategic stock to be utilised as a source of spares for similar transformers in the fleet that remain in service.

Some of our older power transformers have off-tank radiators; this layout has triggered a new initiative to procure a variety of power transformers of sufficient capacity, impedance and off-tank radiator design to enable existing building enclosures to be used. With the initiative to add off-tank radiator power transformers to the fleet procurement strategy, it is anticipated to significantly reduce power transformer bay demolition and civil rebuild costs that would otherwise be unavoidable with Vector's present standard on-tank radiator rectangular footprint design.

Tap changers are integrated components of transformers so are typically replaced when the associated transformer reaches end of life. However, if and where required, a tap changer will be replaced as a separate entity if a transformer is still in good asset health. Vector has only replaced a few tap changers during refurbishment.

As described in the previous section, the availability of spare parts for tap changers guides our decision on whether to refurbish or to replace a power transformer. Replacement parts for certain older generation tap changers are almost impossible to source and decommissioned tap changers are used for spare parts where possible.

12.4.5 FORECAST SPEND

Figure 12-7 below shows our forecast capital spend for the complete replacement programme of power transformers as well as provision for refurbishment in the AMP period. Full details of the individual transformer replacements are given in Section 12 Appendix.

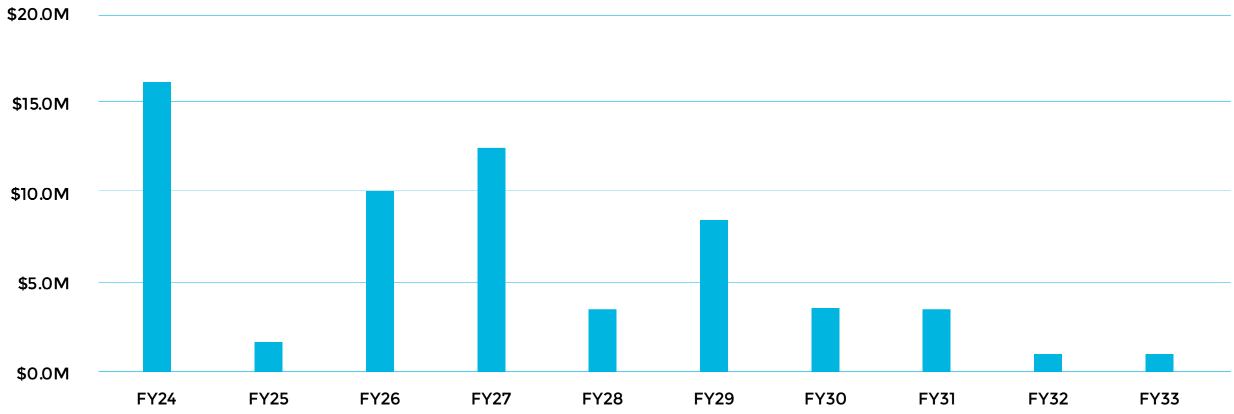


FIGURE 12.7: FORECAST CAPEX – POWER TRANSFORMERS

12.5 Underground cables

This section describes our cable fleet and provides a summary of our associated asset management practices. The cable fleet comprises of:

- Subtransmission (includes submarine cables)
- Distribution
- Low Voltage (LV)
- Joints and terminations

12.5.1 SUBTRANSMISSION

The subtransmission cable network transports electricity from Transpower GXPs to Vector's bulk supply substations and zone substations. Vector's subtransmission cable network operates at 110 kV, 33 kV and 22 kV.

The 110 kV subtransmission network originates from Transpower 110 kV GXPs and connects to Vector's bulk supply substations in the Auckland CBD, Kingsland and Wairau Valley on the North Shore. The 110 kV subtransmission network includes the cables installed within the Penrose to CBD tunnel as well as cables buried in underground ducts. The 33 kV and 22 kV subtransmission circuits run from Vector's bulk supply substations and Transpower GXPs to Vector's zone substations and are installed in underground ducts but in some instances in Vector's tunnels.

12.5.1.1 FLEET OVERVIEW

Key statistics of the 110, 33 and 22 kV subtransmission cable assets are shown in Table 12-8.

CATEGORY	NUMBER OF 110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS	110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS ROUTE LENGTH	110 KV UNDERGROUND SUBTRANSMISSION CIRCUITS IN TUNNELS ROUTE LENGTH	NUMBER OF 33 KV AND 22 KV UNDERGROUND SUBTRANSMISSION CIRCUITS	33 KV AND 22 KV UNDERGROUND SUBTRANSMISSION CIRCUITS ROUTE LENGTH	33 KV AND 22 KV SUBMARINE SUBTRANSMISSION CIRCUITS ROUTE LENGTH
Population	14	28 km	21 km	274	547 km	12 km

TABLE 12-8: SUBTRANSMISSION CABLES FLEET OVERVIEW

12.5.1.2 POPULATION AND AGE

The expected life for subtransmission cables is indicated below in Table 12-9:

CATEGORY	22 KV, 33 KV OIL CABLES	22 KV, 33 KV PILC	22 KV, 33 KV PRIOR TO MID 1980'S XLPE	22 KV, 33 KV PRESENT GENERATION XLPE	22 KV, 33 KV SUBMARINE CABLE - XLPE	22 KV, 33 KV SUBMARINE CABLE - PILC	22 KV, 33 KV SUBMARINE CABLE – OIL CABLES	110 KV XLPE
Onset of unreliability	70 years	60 years	30 years	60 years	60 years	60 years	70 years	70 years
Maximum practical life	100 years	90 years	45 years	80 years	60 years	60 years	70 years	90 years

TABLE 12-9: EXPECTED LIFE OF SUBTRANSMISSION CABLES

The figures above are based on EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience.

Figure 12-8 below summarises the population and age of our 110 kV, 33 kV and 22 kV subtransmission cable fleets.

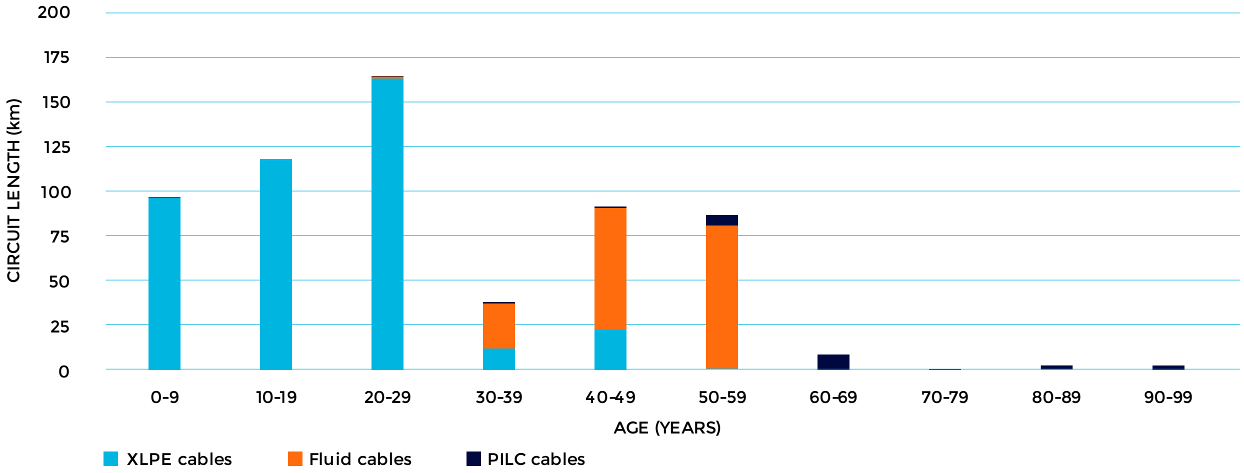


FIGURE 12.8: SUBTRANSMISSION CABLE FLEET AGE PROFILE

12.5.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

General: Subtransmission cables have faulted 51 times over the last 10 years with most of these attributed to joint failures. Piecemeal repair or replacement for these types of cables and joints is not cost effective. Because subtransmission cables operate at an N-1 security level, faults do not normally result in loss of supply and therefore contribution towards SAIDI and SAIFI is mitigated under an N-1 contingency.

We have identified that the trend of increasing frequency of sustained high temperatures over the summer months presents a risk of premature degradation to all underground cables when it coincides with low soil moisture content and increased cyclic loading. To manage this risk Vector reviews the ratings of its subtransmission cable fleet using CYMCAP cable thermal rating software every two years.

110 kV cables: The oldest 110 kV cables in Vector's fleet are the two cables from Mt Roskill GXP to Kingsland zone substation which have been in service since 1965 (57 years old). The 110 kV cables to Pacific Steel were installed in 1982 and the remainder of the fleet after that. The maximum practical life of 110 kV cables and their accessories is projected to be approximately 90 years and we do not expect any material deterioration of these assets over the next 10 years.

22 kV/33 kV PILC cables: We have identified that for some 33 kV and 22 kV PILC cables in our aging fleet, there is an increasing contribution to SAIDI but others are performing well. This specific population is viewed as the type at highest risk and is therefore being closely monitored.

22 kV/33 kV oil filled cables: An average of four outages per year over the last ten years are attributable to oil filled cables, with leaking cable joints being the main cause. While the trend of oil loss over the entirety of the fleet of oil filled cables has been rising, an increased focus over the last two years has seen this trend decrease due to improved management practices. There is an industry wide risk that the resource pool required to repair and maintain oil filled cables is reducing at a time when there will be an increased need to manage this type of cable fleet. Accordingly, Vector is working with its FSPs to ensure the appropriate skills and resources are available to manage this risk going forward.

22 kV/33 kV XLPE cables: While the current versions of this cable are very robust, the early generations of XLPE (between 1970-1990) had manufacturing defects which could result in premature failures of the cable. Vector have experienced several repeat failures on the early generations of XLPE, resulting in the establishment of a proactive replacement programme for the population.

12.5.1.4 CONDITION AND HEALTH

Vector has recently developed a CBARM model to assist to inform the replacement programme for subtransmission cables. This model is based on age, condition and criticality. The present (RY23) risk level for the subtransmission cables fleet is shown below in Figure 12-9.

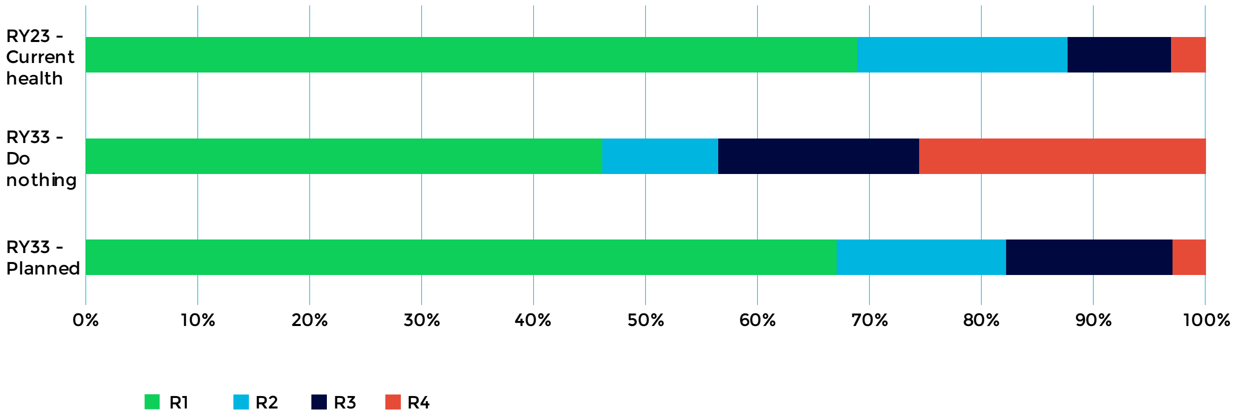


FIGURE 12.9: SUBTRANSMISSION CABLE FLEET RISK LEVEL

The above indicates that the subtransmission cable fleet is currently in good condition. However, without intervention from Vector's investment programme, an increasing percentage of the asset fleet will be approaching end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

12.5.1.5 MANAGEMENT STRATEGY

The management strategy for subtransmission cables is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers and close scrutiny by the Vector Asset Management team. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.1.6 DESIGN AND CONSTRUCT

New cable circuits generally comprise three-core or single core cables with XLPE insulation, copper wire screen, PE or PVC outer sheaths with a water blocking layer. Cables sizes and types are standardised across the network to reduce the required types of spares and accessories and simplify the procurement and maintenance activities. Vector utilises CYMCAP cable thermal rating software to model the installation details and backfilling within the installation corridor to ensure optimum ratings for a cable circuit(s). This model considers the physical cable installation environment, prospective future load profiles and other external factors such as heat sources from other cables. The CYMCAP software is also used to determine the ampacity of subtransmission circuits and the impact of adjacent cable circuits.

Vector standards, ENS-0191 and EN-0032 detail the technical requirements for the procurement of subtransmission underground cables. Vector balances the benefits in economies of using a single cable manufacturer against the risks of not having supply chain redundancy and reduced standardization and potential costs.

In addition, Vector maintains a strategic stockpile of common cable types and sizes to ensure that critical spares are available for fault events.

Vector has design standards (refer to Appendix 2 in Section 17) in place that ensures that cables are installed in a consistent, cost-effective manner and in accordance with best practice to ensure that asset life is maximised.

12.5.1.7 OPERATE AND MAINTAIN

Maintenance activities for subtransmission cables revolve around preventing third party damage via proactive patrolling and inspection of construction and subdivision sites. In terms of checking the condition of existing cables, partial discharge testing is undertaken on older cables in the fleet to identify any issues or emerging trends and inform a proactive cable replacement programme of works

The oil filled cable fleet is well maintained by trained oil mechanics and condition assessed by our engineering specialists. The oil pressure in oil filled cables is monitored and alarmed to the EOC via the SCADA system. This enables us to respond quickly to loss of pressure and repair a defect before it turns into a cable fault.

Vector's maintenance standard ESM301 details the planned, corrective and reactive maintenance requirements for its subtransmission cables. The planned maintenance programme for our subtransmission cable assets is summarised below in Table 12-10.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection on subtransmission patrol	1 Week
Inspection	Inspection on oil and gas cables and drums in strategic stock	6 Months
Inspection	Inspection on oil truck & trailer inspection	6 Months
Inspection	Inspection on tunnel cables and their support structures in tunnels	1 Year
Inspection	Inspection on maintenance of waterway crossings - land based inspections	5 Years
Inspection	Inspection on maintenance of waterway crossings. Water based inspection	5 Years
Thermovision Inspection	Thermal inspection on externally visible cable systems (cables, terminations, joints)	1 Year
Servicing	Servicing on cable equipment kiosk/pit maintenance	6 Months
Servicing	Servicing on cross link bonding boxes	2 Years
Testing	Testing on all alarm settings and operating function on gauges and transducers	6 Months
Testing	Test, check and calibrate all cable oil pressure alarm gauges and transducers	2 Years
Testing	Testing on subtransmission cables servicing testing	2 Years
Testing	Testing on cable cover protection unit (SVLs) (Oil and solid cable)	5 Years

TABLE 12-10: PLANNED MAINTENANCE ACTIVITIES FOR SUBTRANSMISSION CABLES

Corrective maintenance activities for subtransmission cables are carried out to further diagnose or restore a network asset to its serviceable condition. To identify and quantify leaks in the oil filled cable fleet, we are investigating the use of perfluorocarbon tracers. Vector uses a risk-based approach for this type of activity as part of its overall corrective maintenance regime.

Reactive maintenance for subtransmission cables involves work needed to return a cable to service, usually after an unplanned outage due to an unforeseen event such as a fault due to third party interference. For every unplanned outage, we undertake post event root cause analysis and record data pertaining to faults to check any developing trend, root cause or issues with a specific type of material or cable.

Cable circuit ratings are reviewed periodically against recorded rating data to check the impact of new circuits that might have been installed and update the ratings in SCADA if necessary. In addition, highly loaded (>60%) circuits are remodelled every two years to review their ratings to ensure it is not exceeded. Vector is investigating the use of distributed temperature sensing to allow the use of dynamic ratings for the subtransmission cable fleet. The challenge with implementing this system has been an appropriate and proper interface to our communications system.

12.5.2 DISTRIBUTION

Distribution cables connect zone substations to distribution switchgear or transformers and connect between distribution transformers and switchgear. Vector's distribution cables are predominantly XLPE and PILC 11 kV cables. However, we also have population of 22 kV distribution cables in the Highbrook, Roskill, Kingsland and CBD supply areas of the network to cater for high density energy needs.

12.5.2.1 FLEET OVERVIEW

Key statistics of Vector's distribution cables assets are shown in Table 12-11.

NUMBER OF 11 KV AND 22 KV UNDERGROUND DISTRIBUTION CIRCUITS	1,022
LENGTH OF 11 KV AND 22 KV UNDERGROUND DISTRIBUTION CIRCUITS (KM)	3,898

TABLE 12-11: DISTRIBUTION CABLES FLEET OVERVIEW

12.5.2.2 POPULATION AND AGE

The expected life for distribution cables is indicated below in Table 12-12:

CATEGORY	ONSET OF UNRELIABILITY	MAXIMUM PRACTICAL LIFE
11 kV PILC	60 years	80 years
Pre 1985 XLPE	20 years	40 years
11 kV, 22 kV present generation XLPE	60 years	80 years

TABLE 12-12: EXPECTED ASSET LIFE FOR DISTRIBUTION CABLES

The figures above are based on the EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience.

Figure 12-10 summarises the population and age of our 11 kV and 22 kV distribution cables.

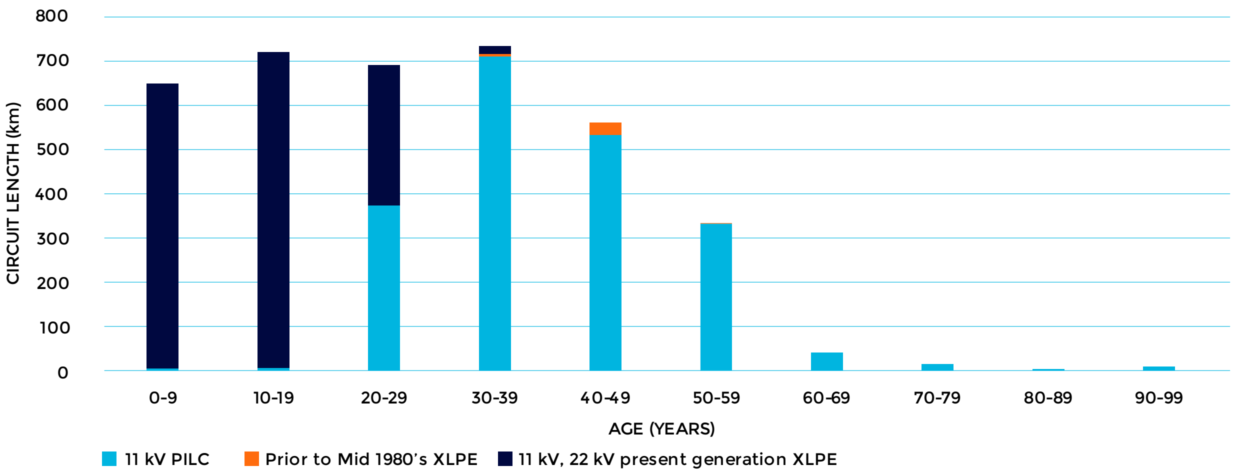


FIGURE 12.10: DISTRIBUTION CABLES FLEET AGE PROFILE

12.5.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector's distribution XLPE cables are performing well with most cables being less than 20 years old and therefore in the early part of their operational life span. The exception to this is our polyloom cables and XLPE cables manufactured and installed prior to 1990. These have exhibited poor reliability due to the integrity issues on the outer sheath. However, our population of polyloom cable is relatively small and the impact on network performance has been minor. Most of Vector's distribution PILC cables were installed between 1950 and 1980 and are approaching the end of their reliable working life. A proactive programme of replacement has been on-going and is continuing to replace 11 kV and 22 kV cables most at risk or in areas of high criticality.

Distribution cables have an average fault rating of 0.064 faults/km with most of these faults attributable to PILC cables. Most faults are found to originate from cable joints. However, the results of some of the pre-commissioning tests upon repair suggest a deterioration of the cable insulation.

Vector has identified that the trend of increasing frequency of sustained high temperatures over the summer months presents a risk of accelerated degradation to all underground cables when it coincides with low soil moisture content and increased cyclic loading. Vector mitigates this risk by modelling cable circuits approaching ampacity limits.

12.5.2.4 CONDITION AND HEALTH

Our CBARM model for distribution cables is based on age, condition and criticality. The present (RY23) risk level for the distribution cables fleet is shown in Figure 12-11.

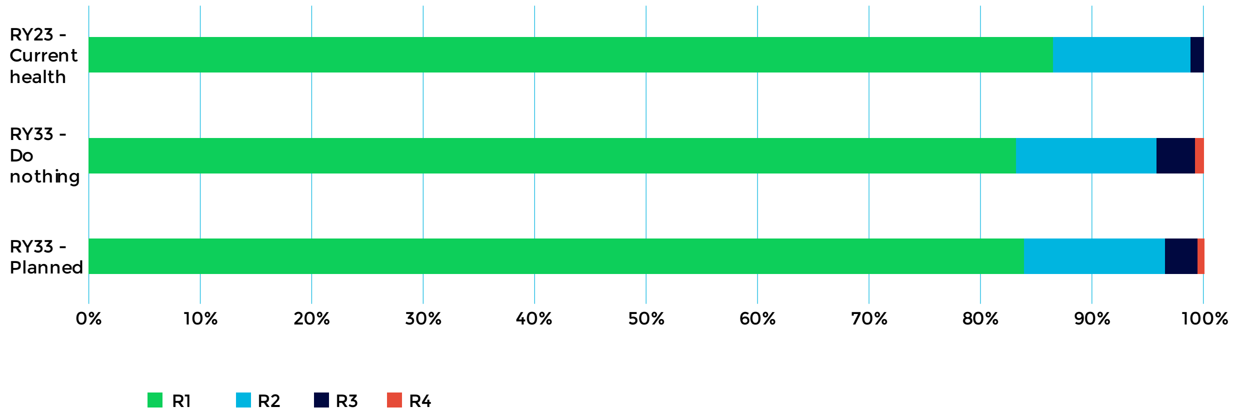


FIGURE 12.11: DISTRIBUTION CABLES RISK PROFILE

The risk profile indicates that the distribution cable fleet is aging. This is predominately due to the PILC cable fleet which has an average age of 40 years. Our analysis shows that approximately 1% of the fleet will approach end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

12.5.2.5 MANAGEMENT STRATEGY

The management strategy for distribution cables is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.2.6 DESIGN AND CONSTRUCT

Vector has standardised the type of cables used in its distribution network to reduce the stockholding of many types (and accessories, simplify procurement and maintenance activities and reduce stockholding costs. Generally, new cables are specified to be three-core or single core cables with XLPE insulation, copper wire screen, PE or PVC outer sheaths with a water blocking layer.

Vector's procurement standard ENS-0127 details the requirements for distribution underground cables. The distribution network uses predominantly 11 kV cables but 22 kV XLPE cables are used in high-density load areas.

Vector maintains a strategic stockpile of the standard range of cable types and sizes used by Vector to ensure that critical spares are available for contingencies.

Vector has design standards in place which ensures that cables are installed in a consistent and cost-effective manner and in accordance with best practice to ensure that asset life is maximized (see Appendix 2, Section 17 for the list of design standards).

12.5.2.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM301 details the planned, corrective and reactive maintenance requirements for its distribution cable fleet. The planned maintenance regime for distribution cable involves a visual condition assessment inspection on externally visible cable systems (cables, terminations, joints) every five years.

Corrective maintenance activities for distribution cables are carried out to further diagnose or restore a network asset to its serviceable condition. This typically involves sheath integrity testing for distribution cables identified with a high risk of failure.

Reactive maintenance for distribution cables involves work needed to return a cable to service, usually after an unplanned outage due to an unforeseen event such as a fault due to third party interference. For every unplanned outage, we undertake post event root cause analysis to ensure that any valuable information relating to the fault is recorded and data is available to identify any trends.

12.5.3 LOW VOLTAGE

Low voltage cables are used for distribution and connection from ground or pole mounted transformers to the customer.

12.5.3.1 FLEET OVERVIEW

Key statistics for the low voltage cable assets are shown in Table 12-13.

CIRCUIT LENGTH OF LV UNDERGROUND CABLE DISTRIBUTION FEEDERS (KM) – AUCKLAND NETWORK	3,607
CIRCUIT LENGTH OF LV UNDERGROUND CABLE DISTRIBUTION FEEDERS (KM) – NORTHERN NETWORK	2,512

TABLE 12-13: LOW VOLTAGE CABLES FLEET OVERVIEW

12.5.3.2 POPULATION AND AGE

Approximately 65% of the LV network in the Auckland region is undergrounded. In some areas, the underground network has been in service for over 60 years. Pockets of underground LV networks exist in the Northern region, but the underground network in the Northern region are generally of lower age. Due to population growth in the Northern region, the underground LV network is expanding.

12.5.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

We are not experiencing any systemic network failure modes in our LV underground network but are seeing a slight increase in faults in older parts of the LV underground network, notably in St Heliers and Mission Bay. The biggest threat and cause of faults in the LV underground cable network is damage by third party excavations and vehicle strikes on above ground pillar boxes.

12.5.3.4 CONDITION AND HEALTH

For legacy reasons, data deficiencies exist for much of the existing LV underground network and hence Vector does not presently have robust data with regards to condition and health for this asset class. Vector is improving its data accuracy for LV cables by recording asset information for all new installations and replacement work.

12.5.3.5 MANAGEMENT STRATEGY

The low voltage cable fleet is not replaced as part of a proactive programme of works but is dealt with on a reactive replacement basis given its relatively localised impact on the network.

Vector considers the improvement of existing data records as a top priority for this asset class as it is a critical pre-requisite before the establishment of a formal asset strategy. The ESM505 maintenance standard defines the procedure for data capture and system updates carried out by Vector's field service providers. It also prescribes preventive maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes.

12.5.4 CABLE JOINTS AND TERMINATIONS

Cable terminations and joints are used to join cable sections together or transitioning the cable to busbars or overhead lines. They are a critical component of the cable system for subtransmission, distribution and low voltage cable systems but are often the points of failure.

12.5.4.1 FLEET OVERVIEW

Key statistics of the cable ancillary assets are shown in Table 12-14. The transformer cable termination component of the statistics (as well as the population chart in Figure 12-12) is inferred from the population of our distribution and power transformers due to data unavailability.

TYPE	UNITS
110 kV subtransmission cable joints & terminations	132
33 kV subtransmission cable joints & terminations	1,974
22 kV subtransmission cable joints & terminations	649
22 kV distribution cable joints & terminations	1,399
11 kV distribution cable joints & terminations	61,134

TABLE 12-14: DISTRIBUTION CABLE JOINT & TERMINATION FLEET OVERVIEW

12.5.4.2 POPULATION AND AGE

The expected life for cables joints and terminations are indicated below in Table 12-15.

CATEGORY	ONSET OF UNRELIABILITY	MAXIMUM PRACTICAL LIFE
Subtransmission cable oil filled cable joints and terminations	40 years	60 years
Subtransmission solid cable joints and terminations	40 years	65 years
Distribution joints and terminations	40 years	65 years

TABLE 12-15: EXPECTED LIFE OF CABLE ACCESSORIES

The figures above are based on the EEA Asset Health Indicator (Guide) 2019 and ODV. However, some projections of the lifespans have been amended based on Vector's experience. The graph below summarises the population and age of our cable joints and terminations.

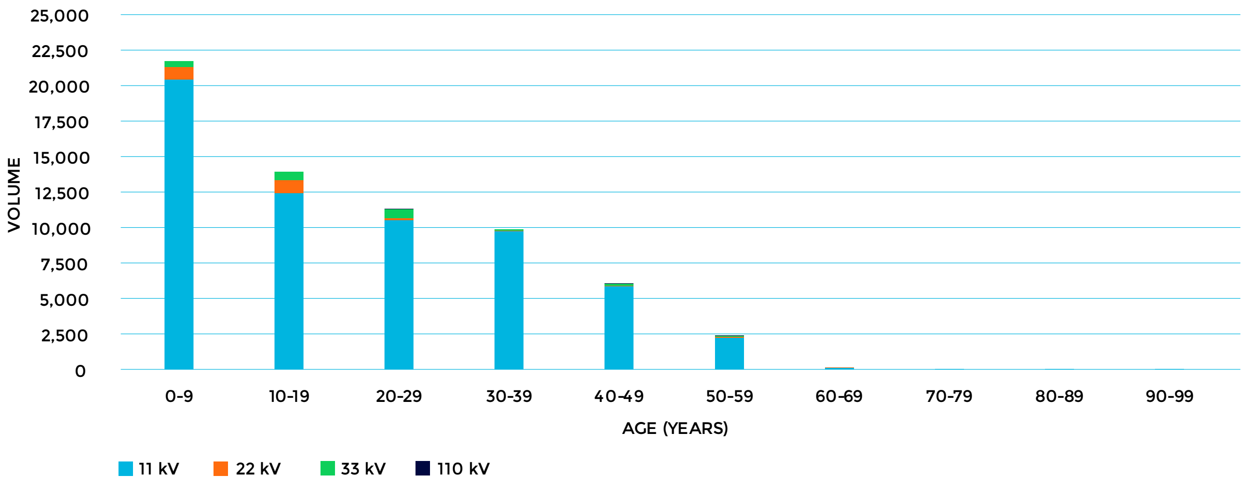


FIGURE 12.12: CABLE JOINT AND TERMINATION FLEET AGE PROFILE

12.5.4.3 CONDITION AND HEALTH

The routine condition assessment of cable joints can be impractical as they are predominately installed underground and require the cable to be offline to undertake testing. As such, the monitoring of joints is reserved for critical circuits and instead, the age of the joint is used as a proxy for its condition. As such, aside from specific known issues or established trends, the condition of cable joints and terminations mirrors that of its associated cable.

12.5.4.4 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector has identified several trends associated with specific types of joints and terminations. There are some known issues associated with the twelve Pirelli (Prysmian) outdoor terminations installed in 1998. The issues concern the internal oil sealing mechanism which can be unreliable. Vector actively monitors these terminations to identify any issues that may lead to premature failure and takes remediation action where necessary.

Vector has approximately 11,100 compression joints on the 11 kV distribution network and close to 1,000 joints in the subtransmission network. These joints were installed between 1980 and 2005 and are now between 11 and 35 years old. Vector have identified a quality issue associated with the jointing techniques used during this period which, in some cases resulted in the premature degradation and eventual failure.

Cast metal pothead cable terminators on the 33 and 11 kV overhead network have degraded over time. The degradation of this type of termination can allow moisture ingress which has the potential to lead to failure.

Inadequate installation practices on a type of '3M' terminations used on three-core cables has resulted in moisture ingress. In some cases, this has led to discharge and eventual flashover.

Vector has experienced termination failures inside ABB SafeLink ring main units, often after a switchgear replacement job where the existing PILC cable termination is reused. Partial discharge caused by re-orientated cables crossing over, or a misalignment between the termination and bushing are thought to be predominate causes of these failures. Apart from exceptional circumstances, Vector standards no longer allow existing PILC cable terminations to be reused in switchgear replacements.

Some cable termination failures in Safelink units have indicated signs of the termination cover boots slipping down and allowing partial discharge to develop. Inline connector termination kits specifically developed for Safelink switchgear are now used to mitigate this. The moulded cover of this kit is shaped to fit the profile of the Safelink bushings which prevents air gaps and increases mechanical support.

12.5.4.5 MANAGEMENT STRATEGY

The management strategy for subtransmission and distribution cable joints and terminations is based on asset health, network criticality and safety. It is informed by asset health data where it is available and is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.5.4.6 DESIGN AND CONSTRUCT

For the procurement of new cable joints and terminations, Vector uses its standards ENS-0191 and ENS-0032. Vector uses the relevant AS/NZS or IEC standard for testing and quality assurance of the cable accessories used on its network. New products go through a well-defined and rigid trial and evaluation process prior to asset introduction.

Joint and termination kits for solid cables are readily available therefore not stocked as strategic stock. However, for oil filled, 110 kV XLPE and submarine cables, straight, stop and transition joints have a lead time for up to six months and therefore Vector maintains strategic spares for these assets.

12.5.4.7 OPERATE AND MAINTAIN

Vector's standard ESM301 details the maintenance requirements for cable joints and terminations. Aside from instances where specific issues and requirements are identified (such as with 110 kV terminations), Vector's typical routine maintenance practices involve the following:

- Externally visible joints and cable terminations in a zone substation are inspected for any signs of deterioration on an annual basis.
- Overhead cable equipment visual inspection including thermographic and acoustic imaging are undertaken every five years
- On-line partial discharge tests are undertaken in accordance with a scheduled programme

12.5.5 REPLACE, RENEW AND DISPOSE

Vector uses its CBARM tool as a risk-based approach to assist to forecast the need for cable replacements. The CBARM model considers asset health, probability of failure and criticality to forecast the need to replace or retire specific subtransmission or distribution cables. Before committing to a decision to replace a cable, Vector validates the output of the CBARM model against test results taken in the field and historical records to ensure the model is providing accurate guidance. Using the outcomes of this analysis Vector has identified the programme of subtransmission cable replacements listed in the Section 12 Appendix to be undertaken within the next 10-year period.

For distribution cables Vector also uses a targeted risk-based approach for replacement. This focuses on replacing the cable sections with a higher than average rate of cable faults and the cable sections where the cable is approaching or has reached the end of its reliable service life. The decision for the replacement of a cable circuit is checked against field test results and historical records.

As LV cables have a low impact on network performance the strategy for the replacement of this asset class is to renew the asset on a reactive basis, at end of functional life or when they pose a public health and safety risk.

Vector will replace its cable joints and terminations on an 'as needed' basis. This usually means that the replacement of cable joints and terminations will coincide with cable circuit replacement or repair. The exceptions to this are when targeted programmes of work designed to address specific risks, are undertaken. For example, the programme of work to replace metal pothead terminations which commenced in 2004 with the last remaining potheads expected to be completed in the next two to three years.

12.5.6 FORECAST SPEND

The forecast capex graph shown in Figure 12-13 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for underground cables is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.

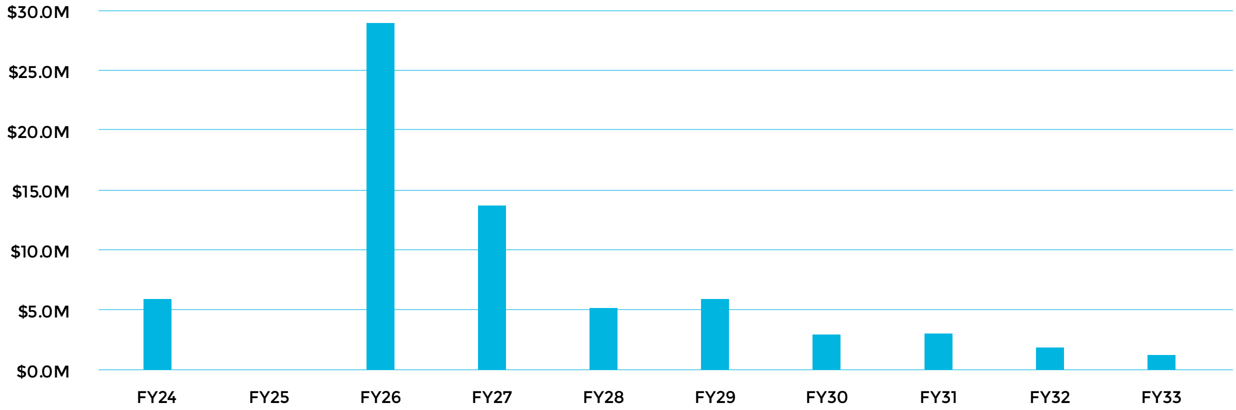


FIGURE 12.13: FORECAST CAPEX – UNDERGROUND CABLES

12.6 Overhead lines

12.6.1 SUBTRANSMISSION

12.6.1.1 FLEET OVERVIEW

Vector's overhead subtransmission circuits transfer electricity from GXPs to bulk supply substations and zone substations and typically operate at 33 kV or above. Vector owns and operates three 110 kV rated subtransmission overhead circuits and 86 circuits operating at 33 kV.

In many instances, multiple subtransmission, distribution and/or low voltage circuits are installed on the same support structures.

12.6.1.2 POPULATION AND AGE

The overhead 110 kV subtransmission network comprises three circuits that run between Transpower's Albany GXP and Vector's Wairau zone substation. All three circuits were constructed in the 1970's with upgrades in 2011 and 2012. The circuits are of the AAC conductor type. The overhead 33 kV subtransmission overhead line network is spread across Vector's network and comprises a mix of copper, ACSR and AAC conductors mostly installed on concrete poles. Most of this network was built between 1970 and 1995.

Table 12-16 summarises the expected lives of the different conductor types. The actual life is affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and the number/magnitude of downstream electrical faults.

Vector utilizes a variety of different conductor types depending on the amount of energy to be transferred and voltage regulation requirements. Each type of conductor has different expected ages and failure modes that are accounted for in the asset management strategies and plans.

TYPE	EXPECTED LIFE (YEARS)	LENGTH (KM)	
		110 KV	33 KV
All Aluminium Alloy Conductor (AAAC)	60	0	4
Aluminium Alloy Conductor (AAC)	60	27	324
Aluminium Conductor Steel Reinforced (ACSR) >100mm2	55	0	29
Copper (Cu) > 60mm^2	70	0	6
Total		**27**	**363**

TABLE 12-16: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet in Figure 12-14 shows that nearly 10% of the asset fleet is up to 60 years old. Approximately 10% of this asset fleet has exceeded it's expected serviceable life and the end of this AMP period it will increase to 35%.

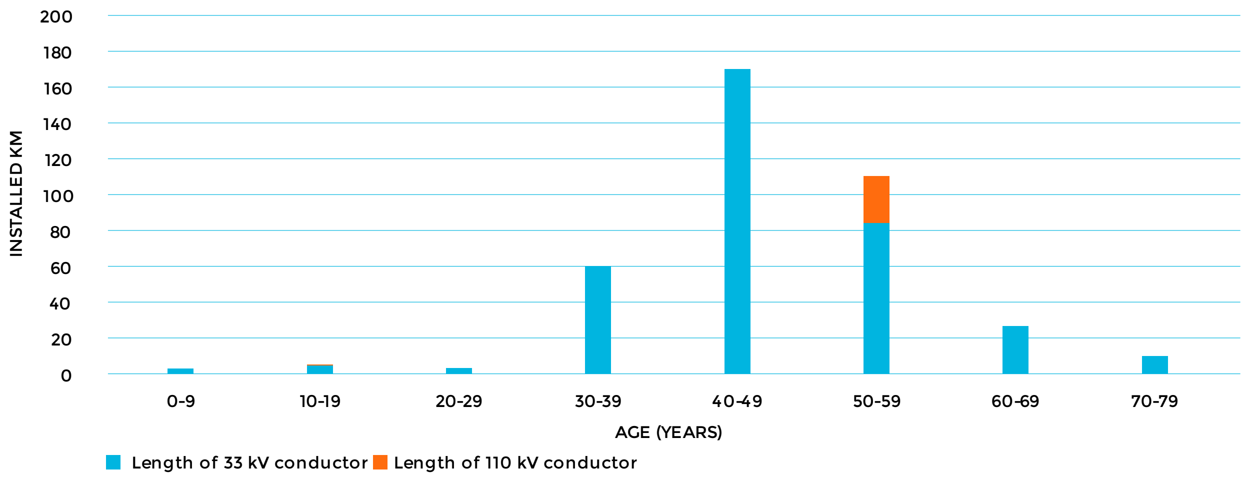


FIGURE 12.14: SUBTRANSMISSION CONDUCTOR FLEET AGE PROFILE

12.6.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

The expected life of each conductor is related to the type of conductor, operating conditions and environmental factors. Conductor diameter is also a factor on life expectancy because smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts. Once they have broken, they are repaired with additional joints. Joints are known to be a likely point of failure, especially under fault conditions where secondary failures can occur. As conductors deteriorate and have increasing numbers of joints installed due to repairs, their reliability is expected to decrease.

Figure 12-15 shows the performance of the subtransmission lines as fault rate per 100km. Subtransmission lines are maintained to have a high level of reliability and have redundancy. A fault on a subtransmission line does not necessarily result in a power outage to customers.

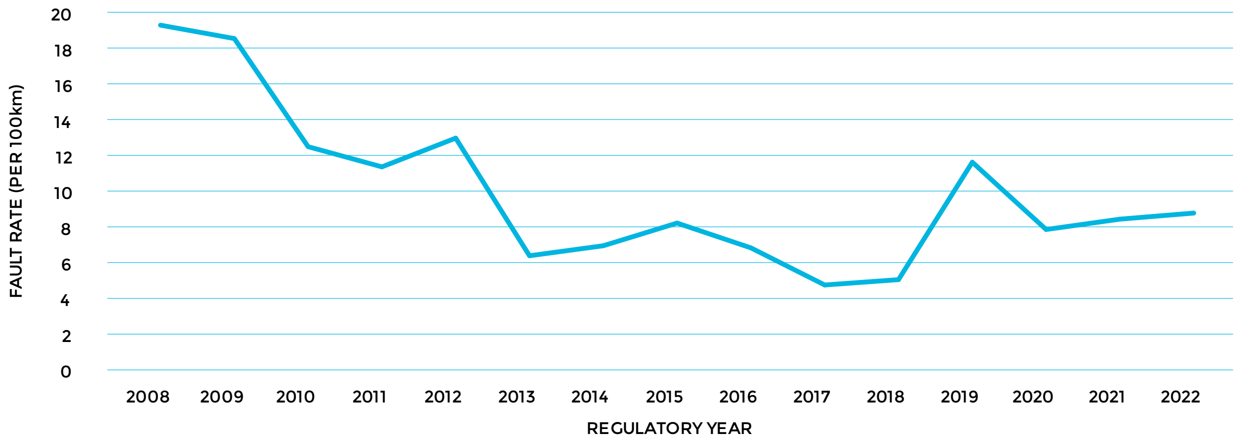


FIGURE 12.15: SUBTRANSMISSION OVERHEAD LINE PERFORMANCE (FAULT RATE)

Other causes of faults and emerging risks identified for this asset fleet that are contributing to its performance are:

- The failure of components of overhead lines, in particular joints
- Vegetation in the proximity of overhead power lines causing transient faults or damage through physical contact. These types of outages are more likely during storms and high winds. This can cause power outages and damage to the conductors that can result in immediate or delayed failure.

Vector has established management strategies to address these issues and ensure the subtransmission network reliability is maintained to comply with the Quality Standards.

12.6.1.4 CONDITION AND HEALTH

The condition of the subtransmission overhead fleet is modelled using CBARM. This model is reasonably well developed and is used to point out network areas that are at risk. Figure 12-16 shows that there is a strong trend of increasing risk if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding its expected life by the end of the 10-year forecast.

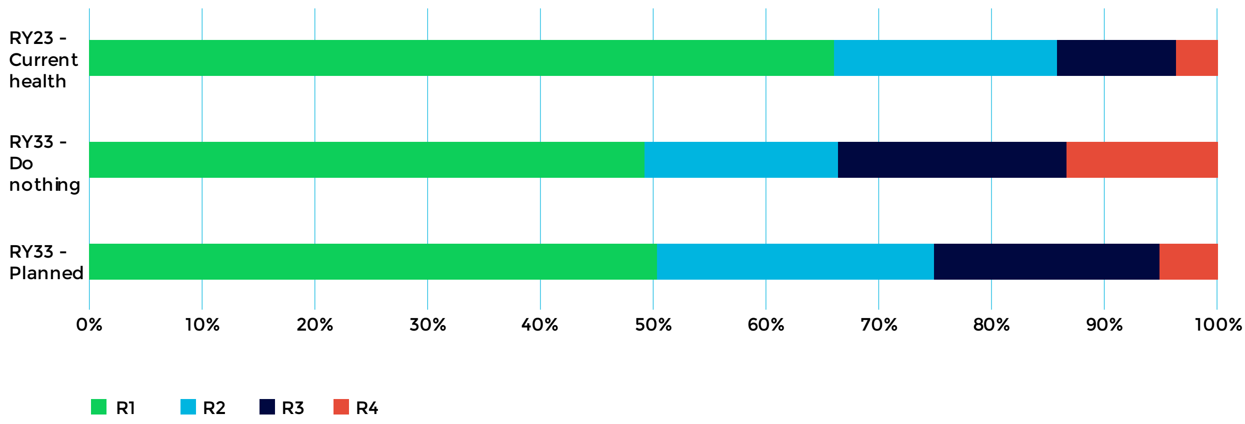


FIGURE 12.16: SUBTRANSMISSION OVERHEAD FLEET RISK PROFILE

12.6.1.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

Vector proactive replacement and refurbishment programmes of work are informed by our CBARM models, condition assessments and criticality. Projects or programmes are initiated to address gaps in service level targets that are either already apparent or are forecast in the next 5-10 years. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.1.6 DESIGN AND CONSTRUCT

The design of the replacement of overhead subtransmission lines are undertaken by Vector with assistance from specialist engineering consultancies and input from the FSPs. The design and performance characteristics are prescribed in Vector's Standard ENS-0153: Specification for overhead conductors. The completed designs are issued to the FSPs for construction and commissioning according to Vector's standards. The design for replacement or refurbishment will also be cognizant of the impact of climate change and how to improve the design to harden against the impact of climate change. Routes will also be carefully selected to not build in flood prone areas or along routes where there is a risk of ground slips.

12.6.1.7 OPERATE AND MAINTAIN

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. The tasks and timeframes are set out in our standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and level of risk to performance and safety.

Most defects are identified through visual inspection. Under the current inspection cycle, conductors are inspected every two years and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. Key tasks carried out during inspections include:

- Inspection of ground clearances.
- Conductor separation and proximity to structures are assessed for adequate clearance.
- Assessment of clearance from vegetation.
- Spans checked for balanced sags.
- Conductors free from broken strands, corrosion and (vegetation or conductor) clash burn marks.
- CCT high voltage conductors are free from insulation damage.
- Joints in conductors are visually secure and not showing signs of overheating.
- Inspection of support structures e.g. crossarms, insulators, foundations, straps etc.

Vector has also implemented the use of LiDAR technology as a tool to carry out height measurements and assessing clearances from vegetation as well as clearances from the ground. The intrusions identified are processed into SAP and are being addressed on a risk prioritised basis.

Vector is also running trials on the use of drones for condition assessments on the overhead subtransmission network.

12.6.2 DISTRIBUTION

12.6.2.1 FLEET OVERVIEW

A distribution overhead circuit is defined as an electrical line that transfers electrical energy from a zone substation to a distribution transformer where it is converted to low voltage. The distribution voltages used by Vector are 22 kV and 11 kV. In many instances, multiple subtransmission, distribution and/or low voltage circuits are installed on the same support structures.

Unlike overhead subtransmission lines, not all distribution feeders have redundancy, and a fault will result in an outage to consumers that can only be rectified with corrective repairs.

12.6.2.2 POPULATION AND AGE

Vector has over 3,707 km (route length) of distribution overhead conductor circuits, representing 45% of its total network line length. Table 12-17 summarises the typical expected lives of the different conductor types along with the length at each voltage level. There is a short length of 11 kV aerial bundled conductor on Vector's distribution network in the Clendon area.

The expected asset life differ for each type of conductor and each type also has a different failure mode which are accounted for in the asset management strategies and plans. The actual life of each conductor type is also affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and number and magnitude of downstream electrical faults. The geographical location of overhead conductor circuits thus plays a major part in its condition and rate of deterioration.

TYPE	EXPECTED LIFE (YEARS)	LENGTH (KM)	
		22 KV	11 KV
All Aluminium Alloy Conductor (AAAC)	60	2	90
Aluminium Alloy Conductor (AAC)	60	0	986
Aluminium Conductor Steel Reinforced (ACSR) >100mm2	55	0	119
Aluminium Conductor Steel Reinforced (ACSR) <100mm2	50	0	1,518
Copper (Cu) > 60mm2	70	0	224
Copper (Cu) < 60mm2	55	0	768
Unknown type	55	0	<1
Total		**2**	**3,705**

TABLE 12-17: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet in Figure 12-17 shows that 60% of the asset fleet is between 30 and 50 years old. Approximately 17% of this fleet has exceeded its expected serviceable life

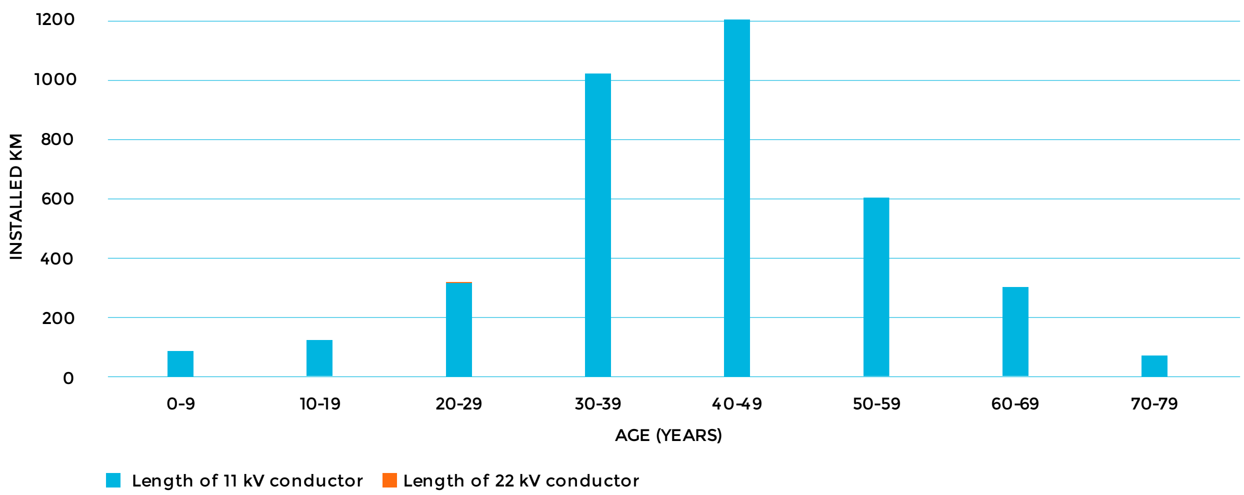


FIGURE 12.17: DISTRIBUTION CONDUCTOR AGE PROFILE

12.6.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Over the last decade, approximately 20% more conductor has been removed (185km) from the network than has been installed (84km). As a result, the length of overhead line is reducing, with an average annual decrease of approximately 6km per year. This reduction is the result of overhead to underground conversions that are driven by Vector, customers and new development in areas where Auckland Council require undergrounding of existing overhead reticulation. This trend is expected to continue for the planning horizon of this AMP.

Conductor diameter affects life expectancy as smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts. Broken conductors are repaired using in-line tension joints which themselves are known to fail due to high current from downstream faults. With the increasing number of joints installed to repair distribution lines, their reliability is expected to decrease.

As shown in Figure 12-18, there has been a long-term trend of increasing faults on the network. Analysis of the data showed that vegetation impacts and the proximity to marine environments are significant contributors to the fault rate: the following are some of the failure modes:

- Vegetation in the proximity of our overhead power lines is a major factor in network outages especially during storms and high winds. In most instances the impacting vegetation is within the growth limit zone but falling trees from outside the zone can also have a significant impact. The power outages and damage to the conductors can either result in an immediate or delayed failure
- Overhead conductors harden over time (anneal) due to wind induced vibration, movement and thermal cycling, resulting in becoming brittle and a reduction of its tensile strength, eventually leading to failure.
- The marine environment is more corrosive due to salt in the air and is generally a windier environment and this contributes to the deterioration rate of conductors. All of Vector's network is less than 15 km from the nearest shoreline, and approximately 50% is within 3 km of the shoreline. Hence, these factors are an important driver of asset condition.
- The failure of components of overhead lines (other than the conductor itself) contribute significantly to interruptions on distribution feeders.
- We are starting to see the impact of climate change. This became especially poignant during the Jan-Feb 2023 cyclone where ground slips put portions of the overhead distribution network at risk
- We have seen an increase in lightning activity especially in the North-western areas of the network

By then end of this planning period, 38% of the distribution overhead conductor population is expected to exceed its serviceable life and in the past four years Vector has embarked on an accelerated proactive refurbishment programme for this fleet.

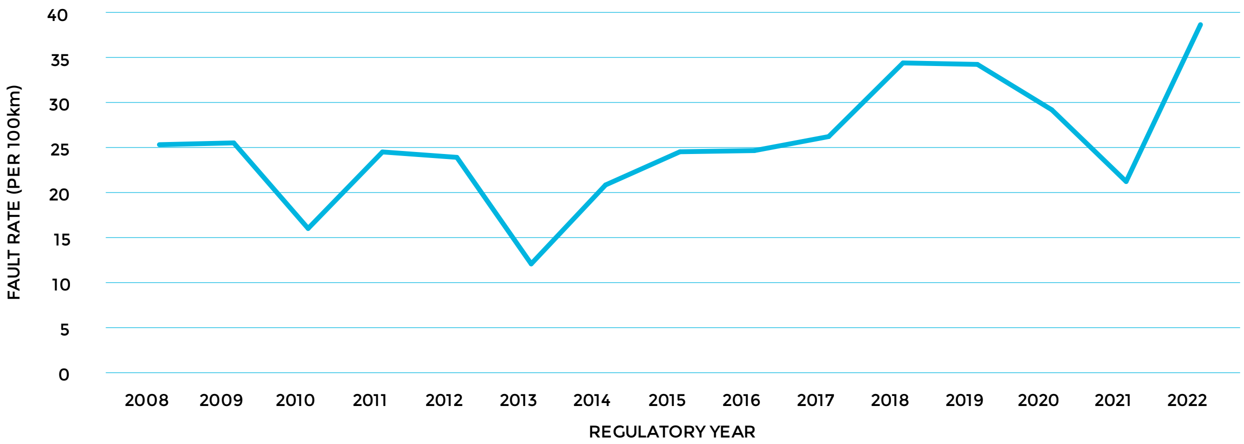


FIGURE 12.18: DISTRIBUTION OVERHEAD CONDUCTOR FAILURE RATE PER 100KM

12.6.2.4 CONDITION AND HEALTH

The condition of the distribution conductor fleet is modelled using CBARM, output shown in Figure 12-19 below This model is well developed and is used to point out network areas that are at risk. The forecast risk of the network is used to develop an intervention strategy and inform the programme of works that will manage the risk to within acceptable limits.

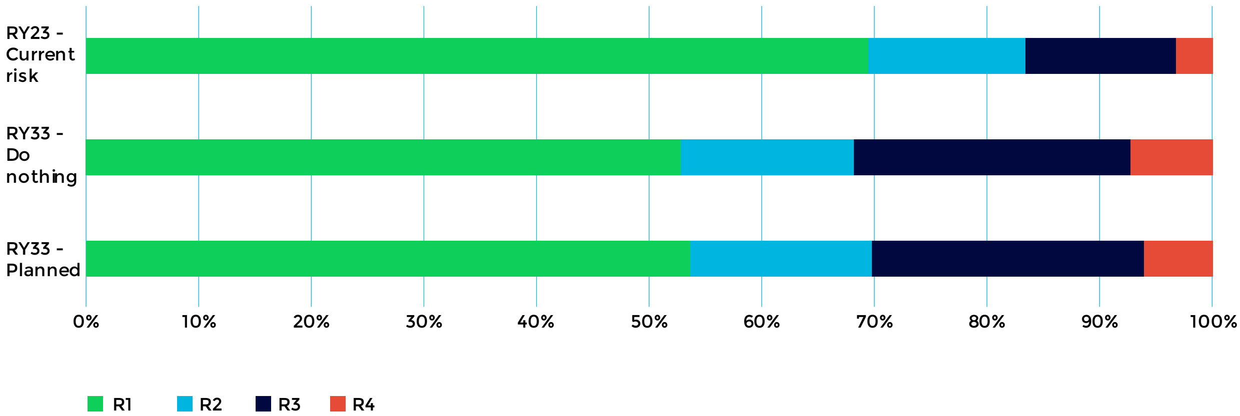


FIGURE 12.19: DISTRIBUTION OVERHEAD CONDUCTOR FLEET RISK PROFILE

12.6.2.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

The life of the conductor is determined by its ability to maintain operating tensions developed by static (gravity) and dynamic (wind) forces. These in turn are influenced by conductor type, size, span length, sag and environmental factors (corrosive elements and exposure to wind).

Vector proactive replacement and refurbishment programmes of work are informed by our CBARM models, condition assessments and criticality. Programmes of work are initiated to address gaps in service level targets that are either already apparent or are forecast in the AMP period. The completion of our replacement and refurbishment programmes during this AMP period is expected to improve the overall resilience and reliability of our overhead network, and accordingly reduce our overhead conductor failure rate.

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.2.6 DESIGN AND CONSTRUCT

Vector uses specialist overhead network design consultancies together with practical input from our FSPs to design the refurbishment of overhead lines. The design and performance characteristics of overhead conductors are prescribed in Vector Standard ENS-0153: Specification for overhead conductors. Design requirements are stated in ESE401, overhead line design requirements and ESE402, overhead design standard design applications. The completed designs are issued to the FSPs for construction and commissioning according to Vector's standards.

The impact of climate change will also be considered in the design of routes for rebuilds and refurbishment and methods to harden construction against the impact of climate change will be added to our standards.

Increased use of lightning arrestors will be implemented on our overhead networks to harden the network against the impact of lightning surges.

12.6.2.7 OPERATE AND MAINTAIN

Vector implements a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance. The tasks and timeframes are set out in our standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through visual inspection. Under the current inspection cycle, conductors are inspected every two years and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. The key tasks carried out during inspections are similar to those detailed in Section 12.6.1

Vector has also implemented the use of LiDAR technology as a tool to carry out height measurements and assessing clearance from vegetation and from the ground. The intrusions identified in a recent survey are now processed into SAP and a corrective program of work has been initiated to remediate them on a risk prioritised basis.

12.6.3 LOW VOLTAGE

12.6.3.1 FLEET OVERVIEW

A low voltage overhead circuit is defined as an electrical line that transports electricity from a distribution transformer from which connections are then taken to customer's premises. The low voltage network operates at 400 V and excludes conductors associated with load control and streetlight systems. The low voltage network is generally a three-phase network i.e. comprises four wires: three phases and a neutral. In many instances, subtransmission, distribution and low voltage circuits are installed on the same support structures.

12.6.3.2 POPULATION AND AGE

Vector has over 4,092 km (route length) of low voltage overhead conductor circuits, which is 50% of its total overhead network fleet length. Table 12-18 shows a summary of the types of LV conductor in the fleet, typical expected asset lives along with the installed route length for each type. Each of these types of conductors have different expected asset lives and failure modes which are accounted for in the asset management strategies and plans. The actual life of each conductor type is also affected by environmental factors (corrosive elements and exposure to wind), mechanical loads, electrical loads and number and magnitude of downstream electrical faults.

TYPE	EXPECTED LIFE (YEARS)	LENGTH (KM)
All Aluminium Alloy Conductor (AAAC)	60	6
Aluminium Alloy Conductor (AAC)	60	1,348
Aluminium Conductor Steel Reinforced (ACSR) <100mm2	50	454
Copper (Cu) > 60mm2	70	278
Copper (Cu) < 60mm2	55	1,565
Aerial Bundled Cable (ABC)	30	31
Unknown type	55	410
Total		**4,092**

TABLE 12-18: ASSET FLEET TYPE COMPOSITION AND EXPECTED LIFE

The age profile of the asset fleet is shown in Figure 12-20. It shows that 80% of the assets are between 30 and 60 years old and that approximately 12% of assets have exceeded their standard asset life. During the planning period of this AMP, an additional 15% of LV conductor is expected to exceed its standard expected asset life. Due to historical data deficiencies for this fleet, an analytical approach was undertaken to allocate an age to each conductor based on its material type, size, age of the development in which overhead LV lines are located, age of associated assets and information gathered from the field. Values are in kilometres with a data error rate of approximately 1%.

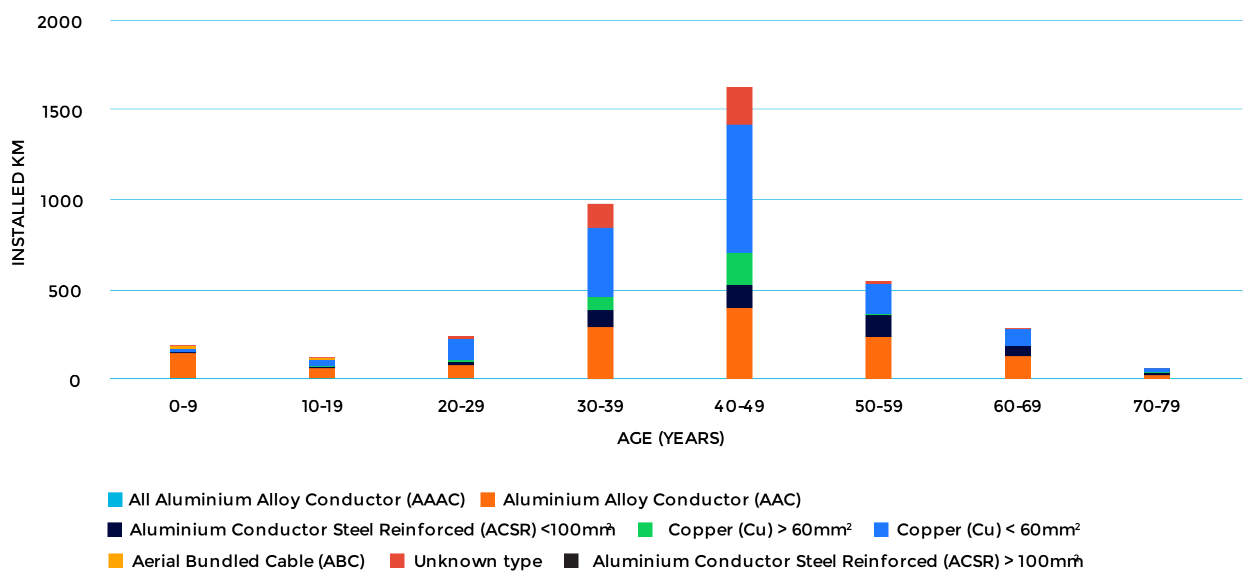


FIGURE 12.20: LOW VOLTAGE OVERHEAD CONDUCTOR FLEET AGE PROFILE

12.6.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Similar to conductors operating at higher voltages, the expected life of each conductor is related to conductor type, operating conditions and environmental factors. Conductor diameter is also a factor on life expectancy as smaller conductors are inherently weaker and are less able to withstand shock impacts from external forces such as vegetation and vehicle impacts. If a conductor fails, it is repaired with additional joints being introduced into the network. Joints are known to be likely points of failure, especially under fault conditions where secondary failures can occur. As conductors deteriorate and an increasing number of joints are installed under repairs, the reliability of such a circuit is likely to decrease.

Analysis of outage data showed that vegetation is a significant cause of faults. Proximity to marine environments also impacts conductor life considerably: failure modes are discussed below.

- Vegetation has proved to be major contributor to faults, especially during storms and high winds and thus a major contributor to a reduction in the reliability indices and customer service levels. Our increasing use of fully covered ABC conductor is assisting to mitigate this risk
- Overhead conductors harden over time (anneal) due to wind induced vibration, movement and thermal cycling, resulting in becoming brittle and a reduction of its tensile strength, eventually leading to failure.
- Proximity to the ocean creates a more corrosive environment due to salt in the air and is generally a windier environment increasing the deterioration rate of conductors. All of Vector's network is less than 15 km from the nearest shoreline, and approximately 50% is within 3 km of the shoreline. Hence, these factors are an important driver of asset condition.
- The failure of components of overhead lines (other than the conductor itself) contribute significantly to interruptions on distribution feeders.
- Reporting of low lines by the public result in disconnection of the supply by Vector to take a no-risk approach to public safety until the situation has been made safe or repaired.
- The impact of climate change was very evident during the Jan-Feb 2023 cyclone when a significant number of outages occurred because of airborne debris and trees undermined by slips falling on conductors.

12.6.3.4 CONDITION AND HEALTH

We are not experiencing any systemic network failure modes in our LV network apart from the impact of vegetation during storms, which impact other parts of the overhead network as well. However, the LV network is experiencing the failure of aging hardware components such as neutral conductor clamps and crossarms and this has impacted customer service levels.

The increasing importance of the LV network as the platform for the flow of energy under the new energy future, with increasing penetration of distributed energy sources such as solar PV and batteries, means that our knowledge of the LV network is already receiving increased focus and this will expand as we go forward.

12.6.3.5 MANAGEMENT STRATEGY

The optimal lifecycle investment considers the balance between asset renewal requiring capital expenditure and the combination of preventive, corrective and reactive operational maintenance expenditure.

In order to deliver network opportunities aligned with our Symphony modelling, our focus on the visibility of our LV network and dynamic management of the LV network will increase. We will continue to maintain, refurbish and upgrade the LV network in line with our Asset Management Objectives, to create a future energy network.

This includes enhancing our capability to model and analyse the behaviour of our LV network, and the customer energy demands placed on it particularly where DER and transport electrification is becoming pronounced. We have defined the use cases to improve visibility of the LV network using modern and cost-effective monitoring devices to measure energy flows in the LV network and trial sites are being evaluated. Data from smart meters and advanced metering infrastructure are key enablers of our LV network visibility strategy

Vector proactive replacement and refurbishment programmes of work are informed by our condition assessments and criticality projects or programmes are initiated to address gaps in service level targets that are either already apparent or are forecast in the next 5-10 years. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.3.6 DESIGN AND CONSTRUCT

The design of new or replacement distribution lines is undertaken by Vector with input from the FSPs and pole engineering specialists as required. The design and performance requirements are defined in Vector Standard ENS0153: Specification for overhead Conductors. The completed designs are issued to the FSPs for construction and commissioning.

The increasing frequency and severity of climate change events emphasis the need to design and construct a more reliable and resilient overhead LV network.

12.6.3.7 OPERATE AND MAINTAIN

Vector undertakes a wide range of routine and operational tasks covering asset inspections, condition-based testing and maintenance as detailed in our standard ESM401. The preventive tasks are designed to uncover non-compliant or serviceability defects which are then treated as corrective maintenance actions or an asset renewal action depending on the extent and risk to performance and safety.

Most defects are identified through visual inspection. Under the current inspection cycle, conductors are inspected every two years and any defects are recorded against the nearest pole as it has a point location and unique identifier in GIS. The key tasks carried out during inspections are similar to those detailed in Section 12.6.1

Any identified defects that render a potentially unsafe situation to the public or property are repaired, replaced or isolated as soon as practicable. Remediation timeframes are based on likelihood of failure creating an unsafe situation and interruption to consumers. Vector is also currently using LiDAR technology as a tool to carry out height measurements and assessing clearance from vegetation, ground and buildings.

12.6.4 SUPPORT STRUCTURES

12.6.4.1 FLEET OVERVIEW

Overhead support structures include towers, poles, crossarms and associated pole and conductor hardware. These are designed to carry overhead conductors of all voltages under a wide variety of configurations. The support structures must be able to withstand design loads that are generated by the equipment fixed to the pole for the expected lifetime of the asset. Vector has a variety of concrete (reinforced and pre-stressed), wood (hardwood and softwood) and composite (fiberglass) poles, as well as steel monopoles and lattice towers.

12.6.4.2 POPULATION AND AGE

Overhead supports are described by the highest voltage conductor that is attached to the structure, that is - HV (110 kV), MV (33 kV, 22 kV or 11 kV) and LV (400 V or 230 V). It is common for supports to have conductors of two or more voltages installed on them.

As shown in Table 12-19, approximately 92% of Vector's fleet of 125,487 poles are concrete poles. Approximately 4% are wood and the remaining 4% are either steel (predominantly on the subtransmission network), composite materials or unknown material.

MATERIAL	LIFE EXPECTANCY (YEARS)	VOLUME NORTHERN			VOLUME AUCKLAND			TOTAL
		HV	MV	LV	HV	MV	LV	
Wood – Softwood	40		498	1,273		84	1,956	3,811
Wood – Australian Hardwood	60	64	200	62		685	494	1,505
Steel – Lattice Tower	100	46	57					103
Steel – Monopole	100	16	5	1			3	25
Composite	80		216	768		62	395	1,441
Concrete – Prestressed	80	24	10,331	6,694		22,457	25,187	64,693
Concrete – Reinforced	80	34	36,422	10,777		1,837	1,558	50,628
Unclassified			2,445	598		60	178	3,281

TABLE 12-19: POLE FLEET COMPOSITION BY NETWORK REGION

Figure 12-21 below shows that approximately 13% of poles currently exceed their expected life and during the next 10-year planning period, this will increase by an additional 3%. However, these assets are assessed annually for condition and replaced if required. Vector notes that due to incomplete pole age data, this data is considered to be circa 87% accurate.

Prior to 1990, reinforced concrete poles were the preferred type. These were often produced locally and consist of reinforcing bar with concrete poured onto it in a cast. Modern concrete poles comprise a prestressed steel core and spun concrete that results in less concrete being used (lighter) but retains the structural strength as required.

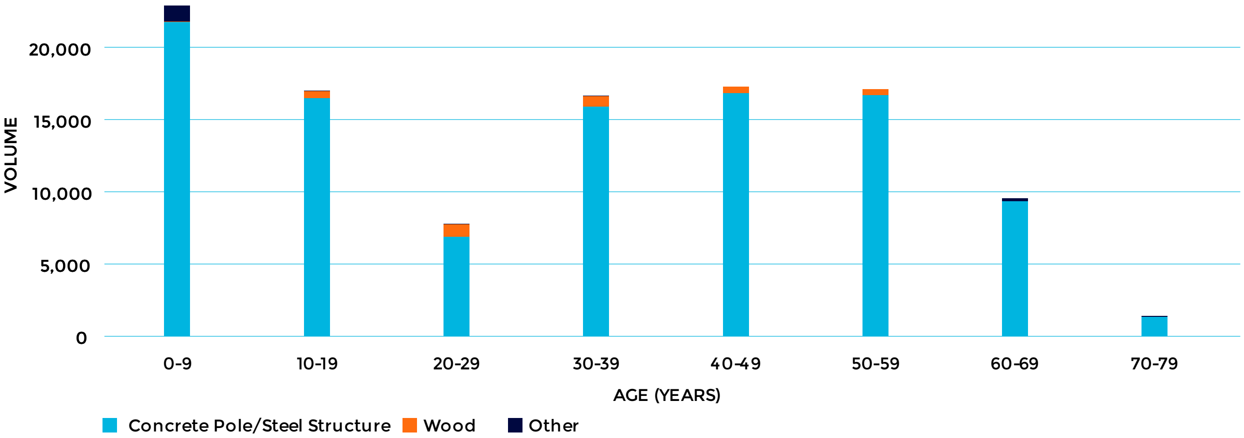


FIGURE 12.21: POLES FLEET AGE PROFILE BY MATERIAL TYPE

12.6.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISK

Although the events shown in Figure 12-22 below have been recorded in our outage recording system as being a 'Pole' failure, investigations have found that an external factor is often the cause of the outage. For example, if a car hit a pole, it is recorded as 'Pole' in the system. Vector has recently improved the way it categorises pole failures which is reflected in the low number of events recorded since 2020.

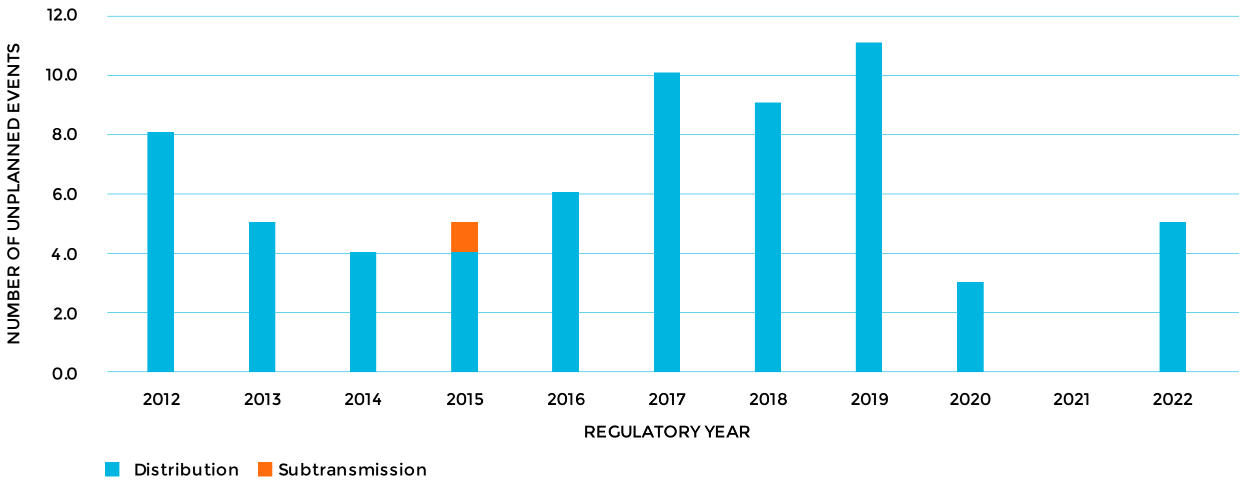


FIGURE 12.22: POLE FAILURES RECORDED ON THE NETWORK

The failure modes and expected life of poles are determined by their material type and environmental factors. As poles age and deteriorate, they lose their mechanical strength and will eventually fail due to the load of the assets installed on them. High winds increase the load on poles. Environmental factors such as moisture and proximity to the ocean accelerate deterioration.

Concrete poles can fail due to 'concrete cancer' where moisture penetrates and causes the reinforcing steel to corrode and crack the concrete. Many of Vector's concrete poles are the 'Vierendeel' poles which are the prestressed type cast into a mould, which are susceptible to the concrete cancer failure mode. This poses a risk to field crews. Prior to any Vierendeel No. 1 concrete pole being climbed, it is inspected and if showing signs of stress, is not climbed unsupported.

KNOWN ISSUE	HOW IT WAS DISCOVERED	HOW IT IS BEING ADDRESSED
Weak Firth Vierendeel poles (especially No. 1 type poles)	Historic design	Work practice (do not climb unsupported, replace when changing the load)
Poles with unknown ownership	GIS legacy data	No current treatment
Pole with customer ownership not being adequately maintained	Observed failure trend	Proactive right of way survey and pole replacement
Poles owned by other utilities with different asset management capabilities	Observed failure modes	Work practices – do not climb

TABLE 12-20: KNOWN ISSUES AND RESOLUTION FOR POLES

12.6.4.4 CONDITION AND HEALTH

In the absence of a developed CBARM model, Vector uses an aged-based assessment to describe the condition of its pole fleet. Figure 12-23 shows that there is a trend of deteriorating condition if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding its expected life at the end of the 10-year forecast.

Vector has developed an intervention strategy to replace at risk overhead supports during the current AMP period.

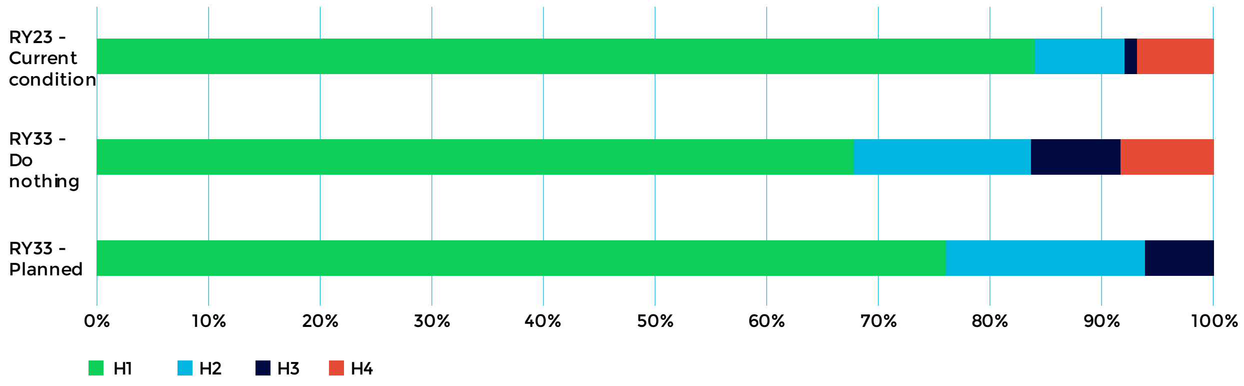


FIGURE 12.23: POLE FLEET CONDITION PROFILE

12.6.4.5 MANAGEMENT STRATEGY

Vector uses a condition-based approach that considers asset health and safety to identify the need to replace or retire specific poles. 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, natural environment, public exposure, access and the load that is being supported. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.6.4.6 DESIGN AND CONSTRUCT

Vector has several approved pole designs covering concrete, steel or composite materials. Vector has largely stopped the installation of new wooden poles in the network because unlike the other pole types, timber requires regular specialist inspections to assess the integrity of the timber through a wood pole's life cycle. In the rare occasion where Vector does install a new wooden pole, these are procured on a "made-to-order" basis.

Poles on the 110 kV line and some 33 kV tower routes require bespoke solutions, e.g. specifically sized monopoles, and replacements may take several months to procure.

Where overhead supports are replaced, it is Vector's preference that prestressed concrete poles be used. For specialist applications (height or strength requirements), steel monopoles are used. As composite poles are light weight, they can be used in remote locations without vehicle access because they are easier and safer to transport.

When designing the locations of poles and selecting the use of structures the impact of climate change will become an important consideration. For example, areas that are prone to ground slips must be avoided as far as practicable and routes in areas that are flood prone must also receive special consideration.

12.6.4.7 OPERATE AND MAINTAIN

Most defects are identified through visual inspection. Under the current inspection cycle, each pole and its associated pole top hardware are inspected every two years and wood poles are subject to additional testing every five years at just below ground level where decay occurs. All equipment defects are recorded in SAP PM. A tagging system is used during visual indications to tag poles that require replacement. Different colour tags define the timeframe in which remedial action is required.

The routine inspection, maintenance and testing requirements for Vector's overhead structures are currently prescribed in Vector Standard ESM401.

12.6.5 REPLACE, RENEW AND DISPOSE

12.6.5.1 CONDUCTORS

Vector decides on replacement of its overhead subtransmission and distribution lines based on condition observed during field inspections and from the output of the conductor CBARM model. When the condition of part or all of an assembly meets the replacement criteria, the entire assembly is assessed to test for the cost efficiency of replacing just the component or the entire assembly.

A conductor testing regime has also been introduced to improve the assessment of the condition of conductors where visual observation shows suspect conductors. Furthermore, whenever a conductor fails a sample is retrieved and tested for tensile strength and ductility. These properties provide better indication of the condition of a conductor and its need for replacement.

For the overhead distribution network fleet, a targeted program has been established to replace over 88km of overhead conductors for which there is a trend of increasing failure rates. A significant portion of the small conductor fleet is also expected to reach its standard asset life. The key types targeted for replacement are 16mm² Copper conductors and older 21mm² ACSR conductors. Due to these conductors also being in areas with higher population densities, they pose an increased safety hazard to the public as well as a reliability risk. In line with the requirements of the Auckland Unitary Plan, replacement of LV conductor will either be with aerial bundled conductor or with underground cable.

12.6.5.2 SUPPORT STRUCTURES

Vector applies a condition-based approach in managing the pole populations. Each pole structure is inspected on a periodic basis, or if a potential issue is reported, against assessment criteria established in the maintenance standards. The decision to repair or replace is based on the outcome of the inspection and condition assessment. In addition, poles may also be replaced when new assets attached to the pole are added or removed. This is contingent on an engineering assessment being carried out on the existing pole and in accordance with the design standard.

Pole replacements identified for replacement under the tagged inspection regime are forecast as part of the corrective maintenance programme. However, where a proactive overhead line refurbishment project is undertaken each pole in the route will be assessed for replacement and if required, its replacement will be undertaken as part of the overhead refurbishment scope of works. Pole replacement includes the replacement of the hardware.

12.6.6 FORECAST SPEND

Because of its focus on reliability the forecast capex spend for the 10-year AMP period for this asset fleet is shown in Section 11 - Network Resilience and Reliability Management.

12.7 Distribution equipment

This section describes our distribution equipment fleet and provides a summary of our associated asset management practices. The distribution equipment fleet consists of the following six subcategories:

- 11-22 kV overhead switchgear
- Pole mounted distribution transformers
- 11-22 kV Ground mounted switchgear
- Ground mounted distribution transformers
- Voltage Regulators
- LV Distribution system (non-overhead)

12.7.1 11-22 KV OVERHEAD SWITCHGEAR

In the distribution network, overhead switchgear comprising of circuit breakers, load break switches and isolating links are used to control, protect and isolate the network. The function of the switchgear is to provide protection, by interrupting short circuit and overload fault currents, or isolation, by providing a clear open point, while maintaining service to unaffected circuits.

The circuit breakers in the overhead distribution network are typically epoxy insulated reclosers with vacuum interrupters capable of manual operation and remote operation where required. Older designs consist of SF_6 gas insulation, installation of which ceased in 2000.

Load break switches in our network use either epoxy resin, SF_6 gas or air as an insulation medium. These switches are capable of breaking loads and use various methods of extinguishing the resultant arc. We have recently introduced the epoxy resin insulated load break switch (LBS) as a trial to compare performance against the extensively used SF_6 insulated LBS.

Isolating links refer to drop out fuses, knife links and sectionalisers. Drop out fuses and knife links require manual operation to achieve isolation whereas sectionalisers use logic to determine when to operate, based on defined settings. Sectionalisers are used to isolate larger network portions during a fault. Drop out fuses are used to protect transformers, short sections of overhead line and underground cable sections to transformers. Load break switches are used to provide safety isolation to personnel and to reduce the number of customers affected by a planned or unplanned outage.

12.7.1.1 FLEET OVERVIEW

Key statistics of the overhead switchgear assets are shown in Table 12-21.

EQUIPMENT TYPE	POPULATION
ABS/ABI (air break switch/air break isolator)	851
Drop out fuses	9,987
SF_6 gas switch	604
Solid and sectionalising links	496
Reclosers with vacuum interrupters	199
Automated switch with vacuum interrupters	47

TABLE 12-21: KEY STATISTICS

12.7.1.2 POPULATION AND AGE

The expected life for the overhead switchgear fleet is indicated in Table 12-22

CATEGORY	DESIGN LIFE SPAN
ABS/ABI	30 years
SF_6 gas switch	30 years
Circuit breaker (reclosers and automated switches with vacuum interrupter technology)	30 years
Drop out fuse holder	20 years
Drop out fuse	Single use
Solid and sectionalising links	20 years

TABLE 12-22: EXPECTED RELIABLE OPERATING LIFE FOR OVERHEAD SWITCHGEAR

The table above shows the design life of the overhead switchgear assets. However, this is often not the driving factor for replacing the asset. The longevity of each piece of equipment is influenced by other factors including the operating environment, the number of operations completed, maintenance completed throughout the life of the equipment, etc. This results in the retention of equipment within our network beyond their design life as long as the asset is serviceable and can be operated safely.

Figure 12-24 summarises the population and age of our overhead switchgear (Vector notes the level of data error is approximately 10%).

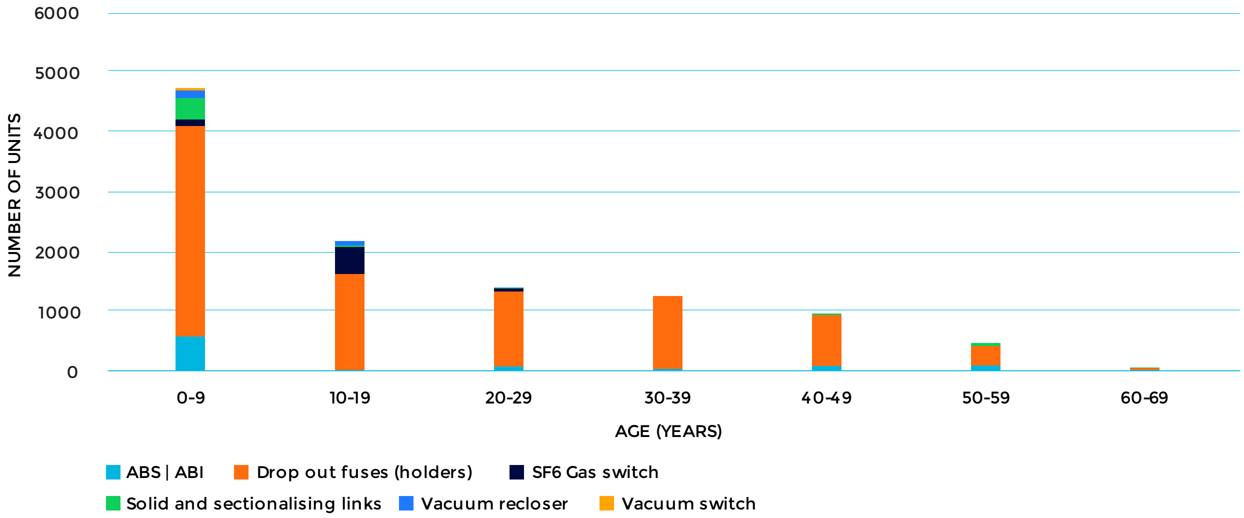


FIGURE 12.24: DISTRIBUTION SWITCHGEARS FLEET AGE PROFILE

12.7.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Asset performance

With proper maintenance on the exterior of a switch to ensure its integrity as well as maintenance on external connections, the gas and vacuum switch fleet can continue to provide trouble-free operation beyond the stated design life. Vector started using these switchgear technologies in the early 2000s which means that the oldest units in the network are only halfway through their stated design life.

Vector has experienced gas leakages from the tanks of gas insulated switchgear. This has led to the re-introduction of air-break switches with arc limiting chutes, to replace earlier than expected failed gas switches. Since this is not a whole of population problem, we will continue to maintain the existing gas insulated switchgear and monitor for additional failures through routine maintenance activities for as long as practicable.

There are approximately 160 ABS/ABI units of pre-1980s vintage. Although these switches are over 30 years old, their operational counts are low and therefore they are still able to adequately perform their functions. Accordingly, Vector plans to continue to undertake periodic inspection and maintenance on these switches. However, for certain types, Vector has embarked on a proactive programme of replacement.

Emerging trends

There has been a considerable growth in the number of transformers in the network over the past ten years due to the growth of Auckland's population. This in turn resulted in an increase of the drop out fuse fleet because fuses remain the preferred method of protection for distribution transformers and spur lines due to their simplistic design, effective operation mode and their economic cost.

Prior to the 2000's there was limited deployment of SF_6 gas switches in the overhead distribution network and use was limited to specific network applications only. From 2003 Vector adopted the use of pole mounted gas switches with the intent for it to be a standard type overhead equipment to replace air-break switches. Together with the uptake of gas switchgear additional reclosers were installed in critical locations of the overhead network driven by an initiative to improve the network SAIDI performance. Due to regular occurrences of gas leakage in the gas switch fleet there has been an increase in the usage of ABS's since 2015. Gas switches are now being utilised in locations where remote-controlled switching is required.

Risks

Due to the age and condition of Vectors ABI overhead switch fleet, live operations using these devices are only permitted if the load on the network at the time of operation is 20 amps or less.

The Vector maintenance standard defines periodic maintenance activities to identify defects or signs of deterioration in the overhead switchgear fleet. The maintenance standard also prescribes corresponding remedial actions to address any identified defects to ensure the risk of equipment failure is managed appropriately.

12.7.1.4 CONDITION AND HEALTH

Vector uses age as a proxy to indicate the condition of its overhead switchgear fleet. The present year (RY23) fleet condition level is shown in Figure 12-25. This shows that there is a trend of deteriorating condition if no action is taken. This aligns with the expected increase in the age of the asset fleet and the percentage of the fleet that will be exceeding it expected life by the end of the 10-year forecast.

Vector has developed an intervention strategy to ensure the condition of the fleet is maintained at current health levels.

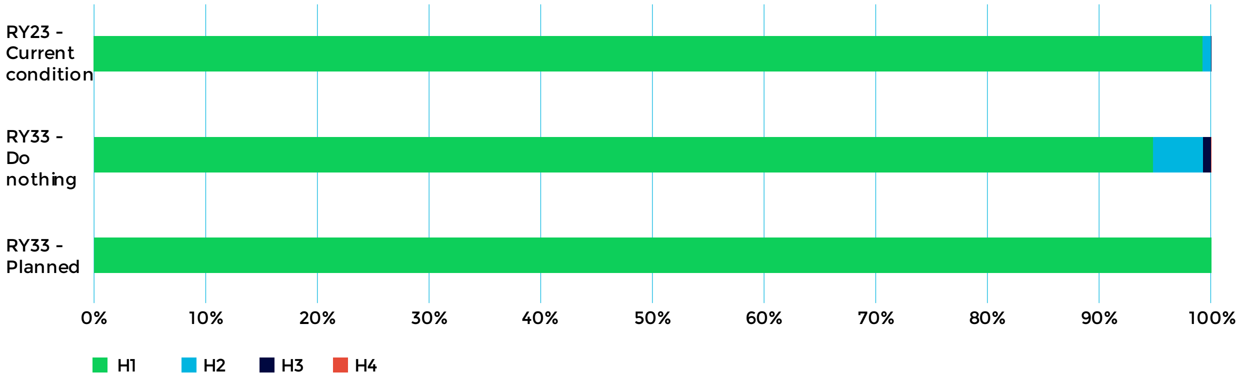


FIGURE 12.25: OVERHEAD SWITCHGEAR FLEET CONDITION PROFILE

12.7.1.5 MANAGEMENT STRATEGY

Vector uses a condition-based approach that considers asset health, and safety to identify the need to replace or retire specific distribution overhead switchgear.

If major off-site maintenance is required to be carried out on a legacy ABS, Vector's present practice is to replace the switch with a new modern equivalent. The old switch will be scrapped because of outdated designs or obsolescence and because they generally require a higher level of maintenance compared with modern equivalents.

12.7.1.6 DESIGN AND CONSTRUCT

Drop-out fuse links and solid links are procured by the FSPs in accordance with Vector standards. All other types of overhead switchgear are directly purchased by Vector and released to Vector's FSPs on request as free-issue equipment or as part of proactive works projects.

Vector is currently reliant on a single supplier for several overhead switchgear types and a priority for Vector is to identify other suitable equipment suppliers in order to establish a minimum of two suppliers for each equipment type to alleviate supply chain and commercial risk. Current procurement challenges include the recent supply discontinuation of a protection relay commonly used across multiple device types, as well as a supply discontinuation of a standard issue overhead switch.

Vector has developed a comprehensive suite of in-house design standards and drawings that define the installation requirements for different overhead switchgear types. All installations must conform to these standards but Vector can give permission for deviations through a change control process.

12.7.1.7 OPERATE AND MAINTAIN

The Vector maintenance standard prescribes preventive maintenance requirements, frequency of inspections, and method of treatment of defects identified either through corrective maintenance or asset replacement processes. The standard also defines the procedure for data capture and system updates carried out by Vector's field service providers.

Modern ABSs are equipped with graphite-coated contacts and this coating adds strength to the contacts enabling them to withstand the wear-and-tear over their life. In a SF_6 gas switch or a vacuum switch all contacts and switching assemblies are housed inside a permanently sealed tank, which render these parts completely inaccessible throughout the switch's life. These concealed parts are designed to provide durable mechanical and electrical operations throughout a switch's life without maintenance.

The equipment only requires a periodic functional test, in which a closing and opening operation is carried out to exercise all moving parts and mechanical chain links to ensure the operational integrity of the switch.

If major off-site maintenance is required to be carried out on a legacy ABS, Vector's current practice is to replace the switch with a new modern equivalent. As such, there is currently no asset refurbishment needed for overhead switchgear other than performing a few simple onsite maintenance activities on the legacy ABSs and ABIs, such as greasing the moving parts or replacing arc horns to maintain their operational efficiency.

Vector's maintenance standard ESM501 details the requirements for the distribution overhead switchgear fleet. Table 12-23 summarises the planned maintenance regime for this asset subclass.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Functional inspection	Functional inspection on all overhead distribution sites including ABS, ABI, gas break switches, reclosers, sectionalisers and HV knife links	1 year
Full Inspection	Full inspection of distribution gas switches	5 years
Full Inspection	Full inspection of distribution automated switches	5 years
Inspection	Inspection on zone substation and point of supply ABS	2 months
Inspection	Inspection on all overhead switchgear including Omnirupter switches but excluding ABS and ABI	5 Years
Thermovision Inspection	Thermovision inspection on ABS in zone substations and point of supply	1 year
Thermovision Inspection	Thermovision inspection on all overhead distribution switches including ABS, ABI, gas break switches, reclosers, sectionalisers and HV knife links	1 Year
Servicing	Full inspection and servicing on ABS and ABI, excluding Omnirupter switches	3 years
Servicing	Servicing on ABS in zone substations and point of supplies	4 years
Servicing	Servicing on sectionalisers and automated gas switches	10 years
Servicing	Servicing on reclosers	10 years

TABLE 12-23: PLANNED MAINTENANCE ACTIVITIES FOR OVERHEAD SWITCHGEAR

Vector does not carry out any electrical testing on its overhead switchgear unless there is a specific issue that needs to be investigated and resolved. Thermal imaging and testing for partial discharge (PD) can be included as part of the testing regime once a decision to test is made.

Vector incorporates risk elements in the overall maintenance approach, such that the treatment of an identified defect is also heavily influenced by consequence and hazard likelihood. For example, assets that have low impact on network performance, such as fuses supplying individual dwellings, are allowed to run to failure because it is more cost effective to replace the failed units rather than inspecting them on a regular basis.

12.7.2 POLE MOUNTED DISTRIBUTION TRANSFORMERS

Pole mounted distribution transformers are essential components in the distribution network that transform the higher voltages down to consumer usable voltages. These are similar to the larger power transformers but are limited to 300 kVA due to their installation at height. Pole mount transformer installations in overhead networks are an economical way to locate the equipment close to the point of supply.

12.7.2.1 FLEET OVERVIEW

Vector has approximately 7,600 pole mounted distribution transformers ranging from 1 kVA to 300 kVA. Vector uses a combination of 11 kV/400 V 3 phase, 11 kV/230 V single phase transformers to step the voltage down to 400 V or 230 V for customer use. Transformers up to 100 kVA are 'hung' on poles and larger transformers are mounted on an elevated platform.

12.7.2.2 POPULATION AND AGE

Table 12-24 provides a summary of the population of our pole mounted distribution transformers by size.

CATEGORY (SIZE)	POPULATION
1 kVA	2
5 kVA	4
7.5 kVA	11
10 kVA	58
15 kVA	1,260
20 kVA	56
25 kVA	104
30 kVA	3,086

CATEGORY (SIZE)	POPULATION
50 kVA	1,802
75 kVA	1
100 kVA	203
150 kVA	27
200 kVA	264
220 kVA	7
250 kVA	1
300 kVA	704

TABLE 12-24: POLE MOUNTED DISTRIBUTION TRANSFORMER POPULATION

Figure 12-26 illustrates the age profile of our pole top distribution transformers. The average age of pole top transformers is 22 years. Our pole top transformer fleet is considered young compared to the typical 30 to 40-year design life.

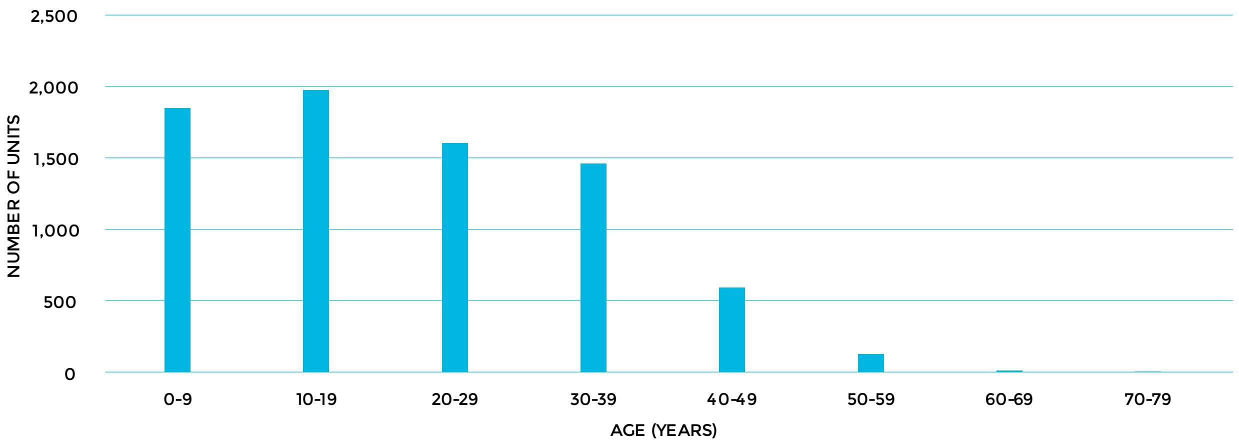


FIGURE 12.26: POLE TOP DISTRIBUTION TRANSFORMER FLEET AGE PROFILE

12.7.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector relies on visual inspections to determine the condition of the transformer fleet but is also informed by the CBARM model. The transformer life depends on loading and operating conditions. If loaded beyond rated capacity for prolonged periods, the expected lifespan is shortened. Typically, these transformers are not operated above nameplate and therefore are not unduly stressed, leading to a low count of replacements due to fatigue.

We have seen increased lightning activity in the network especially in the North-western region. To harden the network against lightning, arrestors will be installed on all new pole mounted transformers. The need to potentially retrofit lightning arrestors as hardening against climate change is being evaluated.

12.7.2.4 CONDITION AND HEALTH

Our CBARM model for pole top transformers is based on age, condition and criticality. The present (RY23) risk level for the pole top transformer fleet is shown below in Figure 12-27.

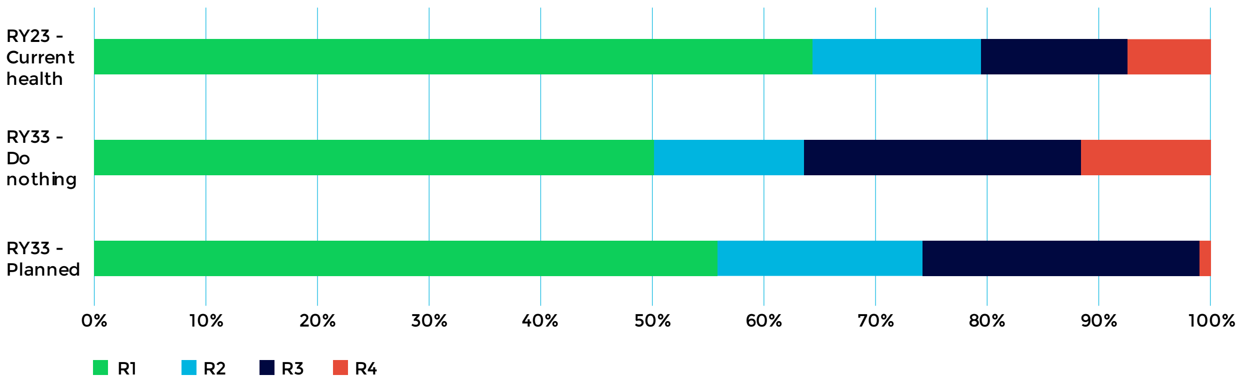


FIGURE 12.27: POLE TOP TRANSFORMER FLEET RISK PROFILE

The risk profile indicates that the pole top transformer fleet is in good condition with less than 12% of the fleet approaching end of life within the next 10 years. Vector's investment programme will significantly reduce the number of pole top transformers within the highest risk category in the upcoming AMP period.

12.7.2.5 MANAGEMENT STRATEGY

The management strategy for pole mounted transformers is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.2.6 DESIGN AND CONSTRUCT

All new pole mounted distribution transformers are manufactured to Vector's equipment specification ENS-0093. Vector has developed a suite of design standards and drawings that define the installation requirements for pole mounted distribution transformers.

To ensure diversity of supply Vector currently has two approved suppliers for this asset class.

12.7.2.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM502 details the planned and corrective maintenance requirements for its pole top distribution transformer fleet. The planned maintenance regime for our distribution transformer assets is summarised below in Table 12-25.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Functional inspection	Inspections that focus on addressing public safety and SAIDI risk as well as record some basic condition information	1 year
Full inspection	Inspections that focus on addressing public safety and SAIDI risk as well as a detailed condition assessment of the asset.	5 years

TABLE 12-25: PLANNED MAINTENANCE ACTIVITIES FOR DISTRIBUTION TRANSFORMERS

Visual inspections are used to check external components because the internal components are sealed and inaccessible for on-site inspections.

Vector runs a refurbishment programme for pole mounted distribution transformers. Every transformer removed from the network is sent to the service depot at ETEL Transformers. The condition of the old transformer is assessed and refurbished if the refurbishment assessment criteria are met, otherwise the transformer is scrapped. It is expected that a transformer' service life will be extended by 25 to 30 years following refurbishment.

12.7.3 11-22 KV GROUND MOUNTED SWITCHGEAR

In the Vector distribution network, ground mounted distribution switchgear is commonly known as Ring Main Units (RMUs) whose function is to connect underground cables to form a meshed network feeder. RMUs are found inside buildings, on private properties or installed in enclosures on the road reserves.

RMUs provide multiple functions – load break switch, circuit breaker and fuse switching. Circuit breaker and load break switching is incorporated in the main connection of the network and the fuse switch is typically used to feed a downstream distribution transformer directly.

12.7.3.1 FLEET OVERVIEW

The fleet of RMUs is made up of oil filled, SF_6 gas filled and epoxy resin insulated equipment of varying ages and manufacturers. The arc-quenching medium used is natural mineral oil, SF_6 gas and air, respectively. The majority of the older RMUs are oil filled due to the industry widely using this method of insulation up until late 2011. Since 2012 SF_6 gas insulated equipment has been the new standard. A small number of epoxy resin insulated RMUs were installed in the 1980s, however this ceased due to safety concerns.

Most of the RMUs in the network are rated at 12 kV and installed in the 11 kV network. There are a small number of 24 kV rated units in the 22 kV network which are all SF_6 gas insulated. The number of installed RMUs is shown in Table 12-26.

EQUIPMENT TYPE	POPULATION
Resin	80
SF_6 gas	3,361
Oil	6,022

TABLE 12-26: NUMBER OF RMUS INSTALLED

12.7.3.2 POPULATION AND AGE

The expected/design life of the differing insulation categories for RMUs is shown in Table 12-27.

CATEGORY	DESIGN LIFE SPAN
Resin	40 years
SF_6 gas	30 years
Oil	40 years

TABLE 12-27: DESIGN LIFESPAN OF RMUS

Figure 12-28 illustrates the age profile of our RMUs. The average age of the RMUs installed in the Auckland region is 28 years, while the average age of the RMUs installed in the Northern region is 16 years. The older equipment in the fleet is predominantly oil insulated, and as discussed above, this is progressively being replaced with SF_6 insulated equipment.

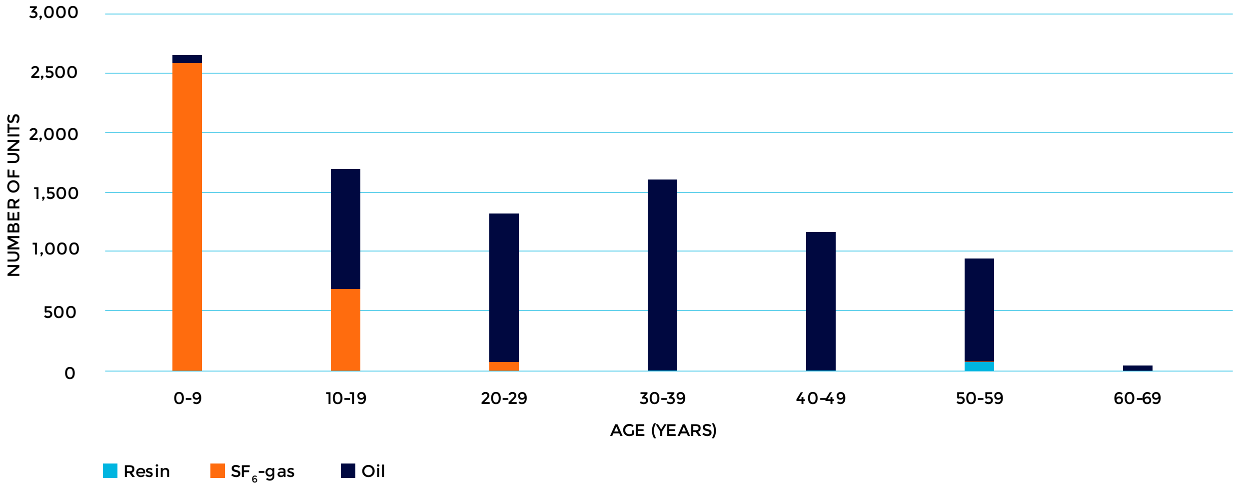


FIGURE 12.28: RMU FLEET AGE PROFILE

12.7.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

RMU service life is a function of the number of duty cycles that the switches experience, the volume and magnitude of through faults, and the RMU's installation environment. Aggressive environmental conditions such as heavy pollution or corrosive atmospheric conditions can have a detrimental effect on the service life of a switch. These operating conditions affect the steel and the protective coatings that protect the switch. A key factor is the effect on the corrosion of steel, which directly affects the integrity of the sealed gas tank and thus its ability to maintain the proper pressure of the SF_6 insulating gas for safe switching operations.

For oil-filled switchgear, deterioration in the tank condition could result in a loss of the insulating oil and/ or exposing the switching assembly housed inside the tank to external interferences, such as moisture or other contaminants. These defects can lead to internal failure in the tank and shortening the life of the equipment.

Accessibility can also affect the longevity of ground mounted switchgear. Vector typically installs distribution RMUs in public spaces, such as footpaths and road reserves. Damage from vandalism or vehicle impact can also lead to equipment failure and reducing the service lifespan.

In 2017, an oil filled Long & Crawford RMU failed catastrophically which has resulted in Vector targeting this make of switchgear for further investigations to ensure the continued safe operation of this type. Vector, in line with other utility operators, is performing ongoing assessment of the arc flash risk at the distribution sites across the network. New installations contain arc quenching capability; so, will comply with safety standards. However, all oil and resin, as well as any SF_6 gas RMUs installed prior to the 2000s, will need to be monitored and maintained to ensure appropriate measures are in place to limit the risk to workers and the public.

12.7.3.4 CONDITION AND HEALTH

Our CBARM model for RMU's is based on age, condition and criticality. The present (RY23) risk level for the RMUs is shown in Figure 12-29.

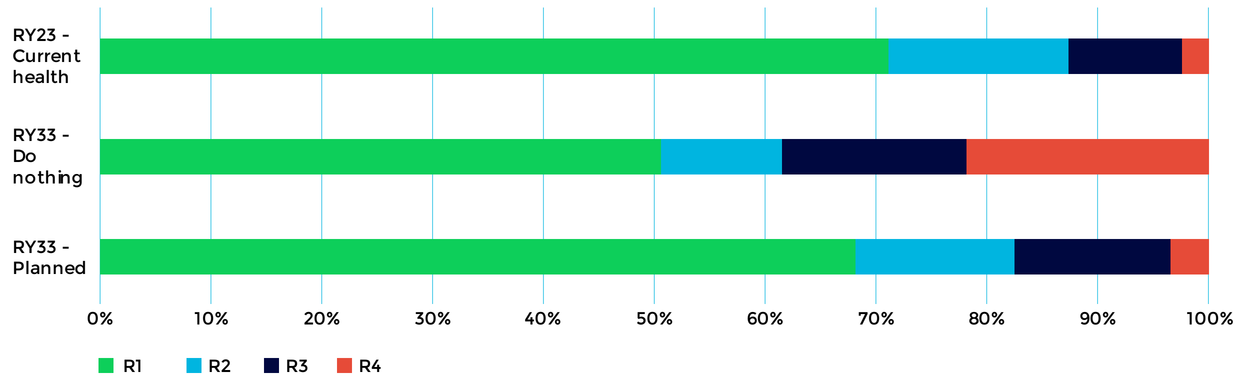


FIGURE 12.29: RMU FLEET RISK PROFILE

The risk profile indicates that the RMU fleet is currently in good condition, but without intervention from Vector's investment programme, an increasing percentage of the asset fleet will be approaching end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

12.7.3.5 MANAGEMENT STRATEGY

The management strategy for RMU's is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The replacement of RMUs is an important part of our program to improve network reliability as described in Section 11.

12.7.3.6 DESIGN AND CONSTRUCT

There are a wide range of switchgear models and makes operating in the Vector network. New RMU's are supplied in compliance with Vector's equipment specification standard ENS-0103. In 2017, to standardise the network design and minimise the required capital investment and operating costs Vector rationalised to two switchgear models from ABB and Siemens to be used for the foreseeable future.

The ABB SafeLink 2 is rated at 12 kV and is used for 11 kV applications. The Siemens 8DJH is rated at 24 kV and is used for both 11 kV and 22 kV applications.

12.7.3.7 OPERATE AND MAINTAIN

Vector's maintenance standard ESM503 details the maintenance requirements for its RMU fleet. The planned maintenance regime for our RMU assets is summarised below in Table 12-28.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Functional inspection	All 11 kV and 22 kV ground mounted distribution switchgear in distribution substations, excluding HV customer with HV Metering	1 year
Full Inspection		5 years
Thermovision Inspection		5 years
Partial discharge inspection		5 years
Full Inspection	Functional inspection on all 11 kV and 22 kV ground mounted distribution switchgear in distribution substations where there are HV customers with HV Metering	2 years
Thermovision Inspection		2 years
Partial discharge inspection		2 years
Servicing	Servicing on all 11 kV and 22 kV oil filled ground mounted distribution switchgear	10 years
Servicing	Servicing on all 11 kV and 22 kV cast resin ground mounted distribution switchgear	10 years

TABLE 12-28: PLANNED MAINTENANCE ACTIVITIES FOR RMU'S

Due to the decision to move away from oil and resin insulated switchgear, these items will continue to be operated until maintenance requirements require removal from the network, at which point they will be scrapped. Given the relatively young age of the gas-filled switchgear population, any unit removed from the network is returned to the supplier's depot for assessment and servicing. The refurbished unit will then be re-issued back into Vector's distribution equipment stock pool for further use.

12.7.4 GROUND MOUNTED DISTRIBUTION TRANSFORMERS

Like the pole mounted distribution transformer fleet, ground mounted distribution transformers are essential components of the distribution network that transform the higher voltages down to consumer usable voltages. Vector uses transformer ratings from 100 kVA to 1500 kVA, with smaller exceptions in remote areas and larger exceptions related to higher load requirements.

Vector maintains a combination of 11 kV/400 V and 22 kV/400 V 3 phase transformers installed with one of three designs – cabinet, cubicle and package.

12.7.4.1 FLEET OVERVIEW

Vector maintains approximately 15,000 ground mounted distribution transformers, predominantly at 11 kV/400 V. The 22 kV/400V population makes up less than 2% of the entire population.

Vector records show 23 different transformer ratings ranging from 10 kVA to 1.5 MVA. Table 12-29 shows a breakdown of the populations by kVA rating.

TRANSFORMER SIZE	POPULATION
<100	834
100	4,279
150	561
200	2,602
250	108
300	3,189
325 to 450	18
500	1,931
750	822
1000	648
1050-1400	2
1500	70

TABLE 12-29: GROUND MOUNTED DISTRIBUTION TRANSFORMER POPULATIONS BY TRANSFORMER RATING

12.7.4.2 POPULATION AND AGE

The average age of the ground mounted distribution transformer fleet is 22 years as presented in Figure 12-30.

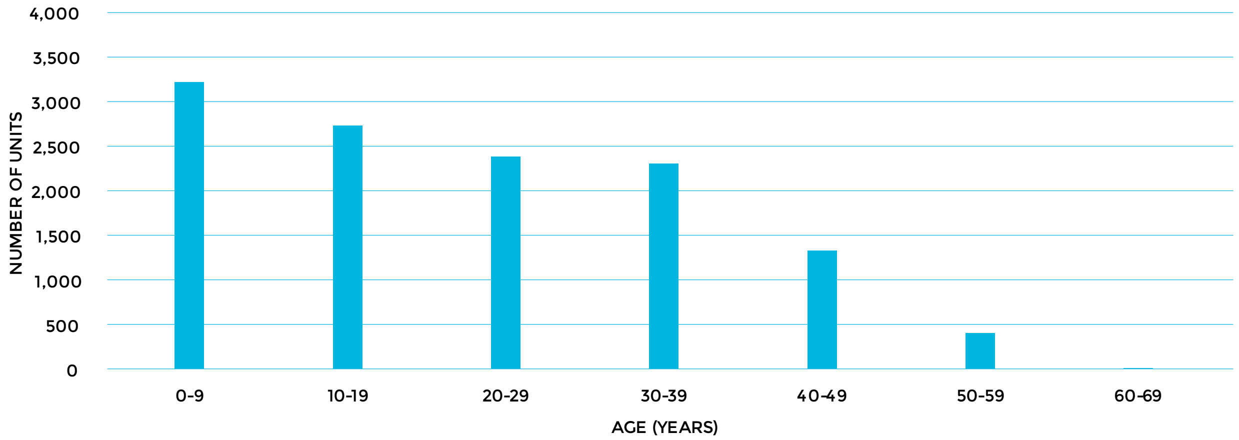


FIGURE 12.30: GROUND MOUNTED DISTRIBUTION TRANSFORMER AGE PROFILE

12.7.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The contribution of ground mounted transformers to the overall SAIDI target is considered small mainly due to a small number of transformers being involved with an outage in any one year.

As shown in Table 12-29, there are a large range of transformer kVA sizes currently installed. Moving forward, Vector has committed to rationalise the range of kVA sizes to limit the number of spares to be held.

A considerable number of ground mounted transformers are currently connected as a daisy-chain through the practice known as “group fusing”, in which a single set of protection fuses is used to provide protection for a chain of distribution transformers. This network design has the advantage of reducing the development cost as the network continues to grow. However, it has a disadvantage of not being able to detect individual transformer faults, especially in detecting faults on the LV terminal bushings - thus driving up fault response time and we also lose the ability to isolate individual transformers if needed. Group fusing is now only permitted in rural subdivisions with two transformers of matching capacity that are both 100kVA and under in rating.

Due to the size of the fuse required to maintain load condition stability, low level faults may remain undetected until the fault develops into a fault significant enough to operate the fuse. Vector has recognised that this poses a high threat to people and property in close proximity and is therefore developing appropriate control measures to mitigate this risk.

Occasionally, a customer with a large load demand may require two or more transformers in parallel. A fault on the HV winding side will trigger the HV protection and isolate the faulted transformer on the HV side. A risk of undetected earth fault exists in the HV delta winding if the faulted transformer is back fed via the LV side from the unfaulted transformer in parallel. Vector's Multiple Transformer Configuration Guide (EGP501) stipulate controls for various installation configurations requiring multiple transformers.

Fire-related events involving distribution transformers are often caused by a combination of high loads and loose connections in congested LV frames. To counteract this Vector has compiled a detailed design standard for ground mounted transformers that clearly describe the maximum number of LV cables and fuseways allowed to be installed. Visual inspections including thermal imaging helps identify this hazard before thermal runaway develops and eventuates as a transformer fire.

12.7.4.4 CONDITION AND HEALTH

Our CBARM model for ground mounted distribution transformers takes into account age, condition and criticality. The present (RY23) risk level for the ground mounted transformer fleet is shown below in Figure 12-31.

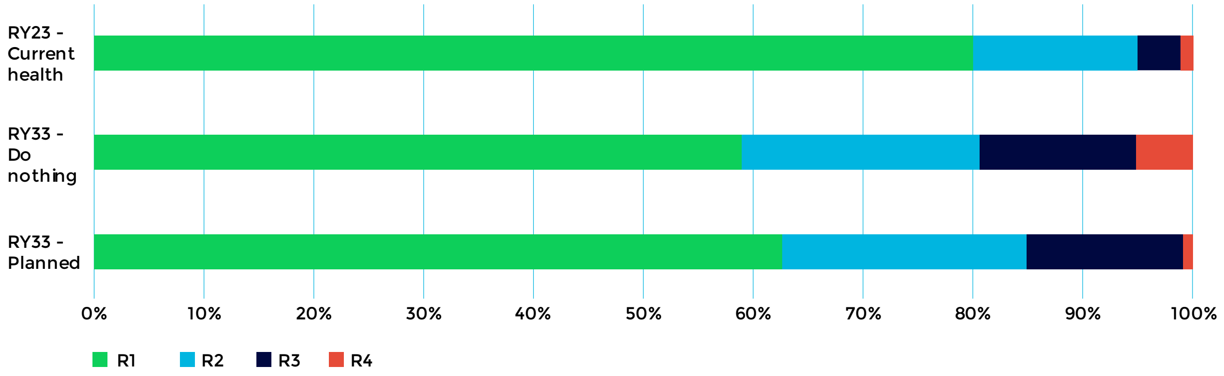


FIGURE 12.31: GROUND MOUNTED DISTRIBUTION TRANSFORMERS RISK PROFILE

The risk profile indicates that the ground mounted distribution transformer fleet is currently in good condition and approximately 5% of the fleet will approach end of life within the next 10 years. Vector's investment programme will ensure that the risk profile of this asset fleet will be maintained at approximately present levels.

12.7.4.5 MANAGEMENT STRATEGY

The management strategy for ground mounted transformers is based on asset health, network criticality and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.4.6 DESIGN AND CONSTRUCT

All new ground mounted distribution transformers are supplied in compliance with Vector's equipment specification standard ENS-0093: Specification for fluid filled distribution transformers. This standard applies to both 22 kV/400 V and 11 kV/400 V transformers.

To ensure diversity in the supply chain Vector currently has two approved suppliers for this asset class. One of these suppliers has also been contracted to provide a refurbishment service for the inspection and repair if practicable, of faulted distribution transformers. Refurbished transformers are released back into the general equipment stocks for re-use on the network.

Vector has developed a suite of design standards and drawings that define the installation requirements for ground mounted distribution transformers. The design documents pertaining to ground mounted distribution transformer are listed in Section 17, Appendix 2.

12.7.4.7 OPERATE AND MAINTAIN

Vector's maintenance standard details our maintenance requirements, including the frequency of inspections, and treatment of defects identified through either the corrective maintenance or asset replacement processes. The planned maintenance regime for our ground mounted transformer assets is summarised below in Table 12-30.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Functional inspection	All 11 kV and 22 kV ground mounted distribution transformers in distribution substations, excluding HV customer with HV metering	1 year
Full inspection		5 years
Thermovision inspection		5 years
Partial discharge inspection		5 years
Full Inspection		2 years
Thermovision inspection		2 years

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Partial discharge inspection	Functional inspection on all 11 kV and 22 kV ground mounted distribution substations in distribution substations where there are HV customers with HV metering	2 years

TABLE 12-30: PLANNED MAINTENANCE ACTIVITIES FOR GROUND MOUNTED DISTRIBUTION TRANSFORMERS

Planned maintenance inspections as listed above ensures that faults are detected early and minor repairs such as oil top up, replacement of holding down bolts, repair of minor oil leaks, minor rust treatment and paint repairs are undertaken on site.

12.7.5 VOLTAGE REGULATOR

A voltage regulator is a device that automatically produces a regulated output voltage from a varying input voltage. The purpose is to hold the line voltage within predetermined limits and to ensure compliance with voltage regulatory requirements at customer points of supply. The regulators in Vector's network are step-voltage regulators, fitted with on-load tap changers to achieve the desired line voltage.

12.7.5.1 FLEET OVERVIEW

Voltage regulators have been deployed at three sites in the Auckland region and four sites in the Northern region to ensure voltage is within permitted limits. Vector uses two types of voltage regulators: the Siemens JFR single phase and the Puhoi three phase. There is a single Puhoi regulator rated to 417 kVA; the remainder are the Siemens models rated at either 165 kVA or 220 kVA.

Single phase regulators are connected in either open delta or closed delta arrangements. A closed delta connection uses three separate single-phase voltage regulators whereas an open delta connection uses two separate single-phase voltage regulators. The difference in range of voltage regulation between the two configurations is the deciding factor in how they are implemented in the network.

12.7.5.2 POPULATION AND AGE

The average age of the regulator fleet is 10 years and considering the 25-year minimum lifespan of the asset, this is a young fleet. Figure 12-32 shows the age profile of the installed voltage regulators.

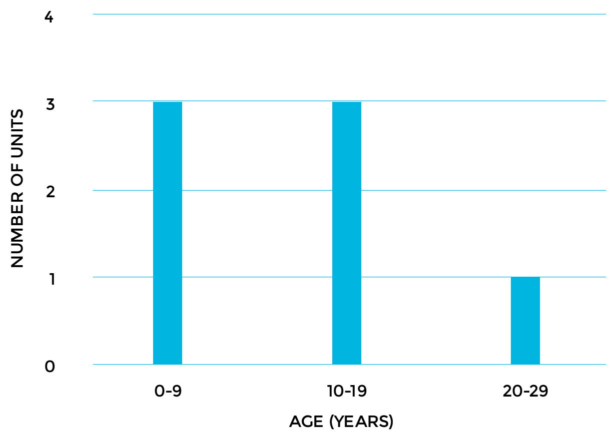


FIGURE 12.32: VOLTAGE REGULATOR FLEET AGE PROFILE

12.7.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There are no recorded network events attributed to voltage regulators. The small population does not allow any meaningful trend analysis. Similarly, there are no risks recorded in Vector's risk management system, attributed to distribution voltage regulators.

12.7.5.4 CONDITION AND HEALTH

The environment in which the regulators in the Auckland region operate is very challenging because they are situated very close to the coast. This results in an elevated level of marine induced corrosion occurring on the regulator tanks and mild steel controller enclosures (the mild steel has a low resistance to corrosion). Electrically they are in good condition and provides reliable service. Only the Siemens JFR models will be used in the future.

12.7.5.5 MANAGEMENT STRATEGY

The management strategy for voltage regulators is based on asset health, reliability and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.5.6 DESIGN AND CONSTRUCT

The existing fleet of Siemens JFR regulators were procured on the basis that they offered the same performance ratings and characteristics as the legacy regulators installed in the network. Vector has identified a need to develop an equipment specification to document Vector's procurement and product requirements for its MV voltage regulators.

12.7.5.7 OPERATE AND MAINTAIN

ESM503 is Vector's maintenance standards for Ground Mounted Distribution Equipment and Voltage Regulators. It prescribes preventive maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes. Vector's approach is to assess the condition of these assets during visual inspections, and to devise appropriate remedial action(s) based on the results of the condition assessment.

Table 12-31 lists the planned maintenance activities and the interval at which they are to be completed.

ACTIVITY TYPE	FREQUENCY
Functional inspection	1 year
Full inspection	5 years
Thermovision inspection	5 years
Partial discharge inspection	5 years
Servicing	10 years

TABLE 12-31: PLANNED MAINTENANCE FREQUENCY FOR VOLTAGE REGULATORS

12.7.6 LV DISTRIBUTION SYSTEM (NON-OVERHEAD)

Vector's low voltage distribution network is the part of the network that conveys electricity from a large network of inter-connected distribution substations to the end users at either 400 V (three phase) or 230 V (single phase).

The ground mounted LV distribution network consists of several key equipment types:

- LV underground cables (including streetlight cables)
- LV switchboard, commonly referred to as LV frame
- LV switchgear
- Pillars
- Pits

LV underground cables were of a paper insulated lead sheathed (PILC) construction until the emergence of polyvinyl chloride (PVC) and cross-linked polyethylene (XLPE) insulated cables in the late 1960s. Since then, PVC has become the predominant type of cable used in the LV network. XLPE is sometimes used in the LV network.

LV frames can be either free-standing or wall-mounted with 3-phase galvanised aluminium or copper busbar arrangement onto which cables and switchgear are terminated or mounted. Its primary function is to distribute power from the incoming main LV incomer to the outgoing distribution cables supplying individual customers or LV feeders.

LV switchgear is designed to perform two main network functions; firstly, to provide overcurrent protection against excess currents due to overloads, short circuit or ground faults and secondly to provide an isolation point. LV switchgear consists of fuses, circuit breakers and visible isolating disconnector units. These devices are mounted in LV frames, pillars, pits and network boxes as required.

Pillars are commonly referred to as an enclosure or a cabinet mounted above ground in which network connections are housed for distribution purposes. Pits serve the same purpose as the pillars, except that the connections are contained in a casing or container buried in the ground. Functionally, there are two types of pillars and pits: link pillars and link pits are used for connecting main LV distribution cables and to facilitate the extension of Vector's LV distribution network when required; service pillars and service pits are used for connecting individual customers onto the LV distribution network.

12.7.6.1 FLEET OVERVIEW

There is approximately 6,100 km of LV underground cable on our network, comprising aluminium and copper conductors with either XLPE, PVC or PILC insulation. Approximately 11% of the installed LV cable fleet lack identifying information relating to core-size or the insulation type. Of the cables with known core type, 54% are aluminium cables due to the lower cost of aluminium compared with copper.

The majority of the 3,500 LV frames on the Northern Network have been installed after 2000, and the total now is almost double the number on the Auckland Network. Due to historical data legacy issues the asset information on LV switchgear is poor and initiatives have been put in place to update data to assist with LV switchgear faults.

There are approximately 163,000 known pillars and pits across the Vector network with 68% installed on the Auckland network. This is made up substantially of service pillars and pits with only 9,300 link pillars and 170 link pits. There are a large number of assets with deficiencies in data recorded for their installation dates. These account for 6% of the known population of pillars and pits and is an area where Vector will need to improve data records.

12.7.6.2 POPULATION, AGE AND CONDITION

Figure 12-33 shows the current known populations of low voltage distribution cables with the recorded installation decade. Values are in kilometres with a data error rate of approximately 6%.

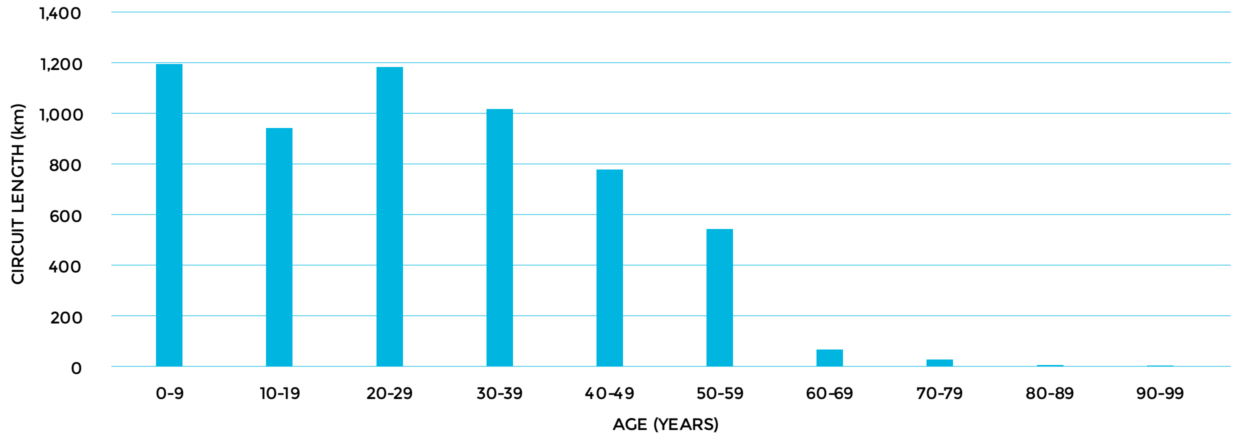


FIGURE 12.33: LV DISTRIBUTION CABLE AGE PROFILE

The average age of the LV cable fleet is 28 years. PILC cables have a design life of 70 to 80 years. Early implementation of XLPE and PVC cables were expected to last 40 to 50 years. With cable technology advancing, the design life of XLPE and PVC has increased up to 60 years. Temperature and the cable's installation environment have the largest impact on cable asset life.

Our fleet of LV frames has an average age of 22 years and an expected life of 30 years so can be classed as aging. Figure 12-34 below shows the age profile of the LV frame fleet. (Vector notes the level of data error is approximately 12%).

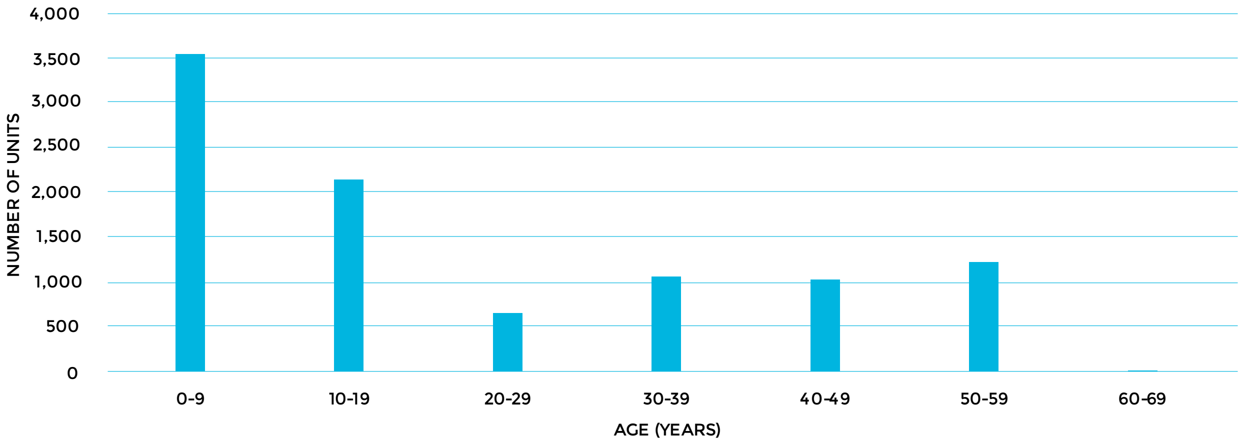


FIGURE 12.34: LV FRAME FLEET AGE PROFILE

Vector maintains approximately 163,000 LV pits and pillars with the majority installed in the Auckland region. Figure 12-35 shows the age profile of the combined pillar and pit populations as these two asset types are not recorded separately (Vector notes the level of data error is approximately 11%).

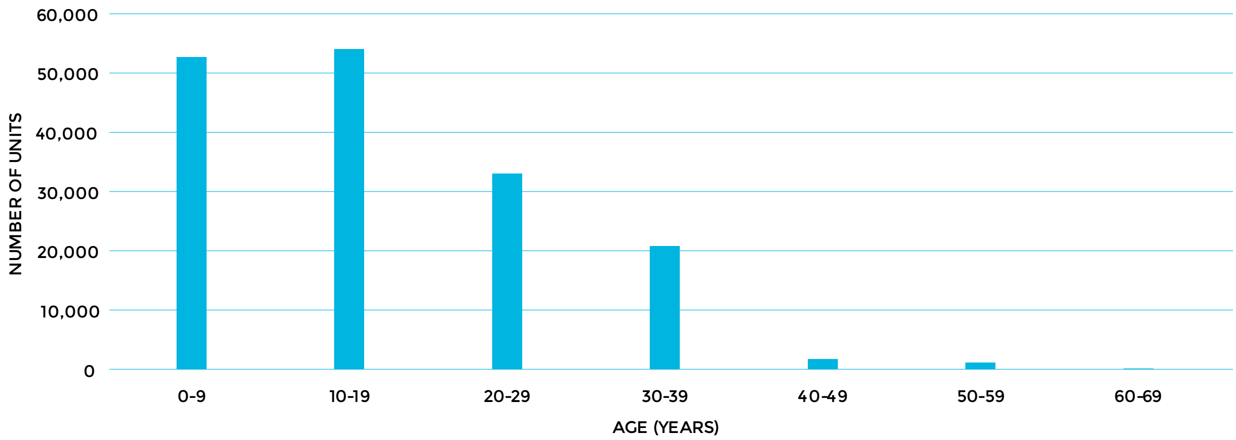


FIGURE 12.35: PILLAR AND PIT FLEET AGE PROFILE

Early generations of pillars were made of cast metal. While larger link pillars have continued to be constructed from aluminium, service pillars have been primarily constructed from plastic since the 1980s. Plastic pillars and pits are expected to last 30 years. Metal pillars are expected to last between 30 and 40 years.

12.7.6.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Unplanned outages involving the above assets only contribute SAIDI minutes if an isolation on the MV network is required for restoration work. In some cases LV isolation is not available at the transformer and restoration work on a LV frame requires the transformer to be isolated for safety. These outages however contribute only a small fraction of SAIDI minutes to the overall SAIDI performance. This is expected since the assets associated here are typically supplying a limited number of customers and is subject to lower network stresses than other asset categories.

Since the 2000s we have had a preference for the installation of underground pits over above ground pillars because of the visual amenity with less equipment visible on kerbs. This is also public preference.

There are several issues which we are closely monitoring in this asset class and includes the following:

- Water ingress susceptibility in solid aluminium conductor LV cable
- Exposed busbars in LV frames
- Failing J Wedge fuse holders
- Failure of neutral connections at customer connections
- Inadequate earthing of metal low voltage service pillars
- Incorrect lugs, loose cable connections causing hot spots
- Building removals without LV isolation confirmed

12.7.6.4 MANAGEMENT STRATEGY

The condition and health of underground LV cables, service pillars and pits are presently monitored on a limited basis. The condition of LV frames is monitored as part of the maintenance programme for ground mounted transformers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.7.6.5 DESIGN AND CONSTRUCT

Vector controls the procurement of LV equipment through the following equipment specifications:

- ENS-0078 Specification for 400 V underground cable
- ENS-0154 Specification for LV service pits
- ENS-0155 Specification for IPPCs for LV distribution pits.

Vector has supply agreements in place with a pool of approved manufacturers and suppliers for each LV equipment category but does not procure directly from them. LV equipment is procured by the FSPs who have their own commercial arrangements with the approved suppliers.

12.7.6.6 OPERATE AND MAINTAIN

Our maintenance standard ESM505 details maintenance requirements, frequency of inspections, and how to treat defects identified either through corrective maintenance or asset replacement processes. It also defines the procedure for data capture and system updates carried out by Vector's field service providers.

The maintenance of the LV distribution system is achieved through periodic visual inspections of the accessible elements of the network (pits, pillars and LV switchgear). Neither invasive maintenance nor electrical testing is carried out unless there is a specific issue that needs to be investigated and resolved.

Thermal imaging is carried out on LV frames mounted inside ground mounted distribution transformers and distribution substations as part of the inspection requirements specified in Vector's standard ESM503.

Onsite maintenance for LV assets is minimal, and we generally operate these assets on a "run to failure" philosophy unless they pose a health and safety risk. The planned maintenance for this asset sub class is shown in Table 12-32 below.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Functional inspection	Functional inspection on service pits, service pillars, link pillars, fuse boxes, network boxes and underground link boxes	1 year
Full inspection	Full inspection on service pits, service pillars, link pillars and fuse boxes	5 years
Full inspection	Full inspection on network boxes and underground link boxes	3 years
Full inspection	Full inspection on LV frames in distribution substations [all Vector enclosures and third-party buildings and excluding HV customer substations]	5 years
Full inspection	Full inspection on LV frames in HV customer substations	2 years
Thermovision inspection	Thermovision inspection on LV frames in distribution substations [all Vector enclosures and third-party buildings and excluding HV customer substations]	5 years
Thermovision inspection	Thermovision inspection on LV frames in HV customer substations	2 years

TABLE 12-32: PLANNED MAINTENANCE ACTIVITIES

12.7.6.7 REPLACE, RENEW AND DISPOSE

Overhead Switchgear

Vector uses its CBARM model to forecast the need to replace specific distribution overhead switchgear. The CBARM model considers asset health, probability of failure and criticality. Before committing to a decision to replace a switch, Vector validates the output of the CBARM model against test results taken in the field to ensure the model is providing accurate guidance.

Ground Mounted Switchgear

Given the disparity in condition and age among Vector's ground mounted distribution switchgear (ring main unit) population, we have chosen to approach the management of equipment renewal both on a condition based and age-related basis.

For relatively new equipment, condition-based replacement is the most appropriate measure used to maintain the serviceability of this portion of the RMU population. This includes all SF_6 gas insulated switchgear, some of the oil-filled switchgears (namely the ABB SD Series 2 and Lucy models) and all epoxy resin installed switchgear.

Aging equipment such as the older models among the Long & Crawford switchgear population, and the combined population of Andelect/Astec/ABB SD Series 1 switchgear are being renewed through a more proactive replacement approach with an aim to progressively remove this equipment from Vector's network.

Under the condition-based replacements, the most common cause for an RMU replacement is expected to be significant degradation in the physical condition due to corrosion or leaks. Other general causes are expected to be due to vehicle damage and network growth.

The proactive replacement program uses the assessments from field service providers in the CBARM framework to identify assets for replacement in a yearly rolling program. Figure 12-29: RMU FLEET RISK PROFILE shows a comparison between the RY33 risk level with and without a proactive replacement programme. Without a proactive replacement program, the health of this asset fleet will steadily decline.

Transformers

The most common cause for a transformer replacement is a significant degradation in its physical condition due to corrosion or leaks, with less common causes being due to vehicle damage and network growth. Historically, 100 kVA, 200 kVA and 300 kVA transformers are replaced most frequently which aligns with these being the predominant populations of transformers.

Since their introduction in the 2000s there have been two 22 kV/400 V transformer replacement based on reactive maintenance. This low rate is expected considering the low overall age of this equipment.

In 2018 Vector developed a condition-based asset risk management (CBARM) framework to inform its programme for the renewal of distribution transformers. Vector now has a proactive distribution transformer replacement programme in place, however pole mount transformers with a rating under 100kVA are replaced only on reactive basis.

Voltage Regulators

Vector's approach to replacement of voltage regulators is condition-based. Presently there is no planned replacement programme for the current fleet of voltage regulators, as they have a relatively young age. It is expected that the existing installations will continue to operate in the network for the foreseeable future. Replacement forecasting for this asset class is based on historical records.

LV Non-Overhead Assets

LV assets are typically replaced when they have reached the end of functional life or pose a public health and safety risk, due to these assets' low impact on network performance. The LV frame and associated switchgear are usually replaced in conjunction with the replacement of a distribution transformer.

Currently there is no proactive replacement programme for the LV distribution system. Programmes to remove specific asset types have occurred in the past, such as the replacement of mushroom pillars and letterbox pillars. We may adopt the same approach in the future for other types of assets as the need arises. Replacement forecasting for this asset class is undertaken on a historical basis.

12.7.7 FORECAST SPEND

The forecast capex graph shown in Figure 12-36 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. Because of their focus on improving the reliability of the network, the proposed capital investment in overhead switches, RMUs and distribution transformers are included in Section 11, Reliability.

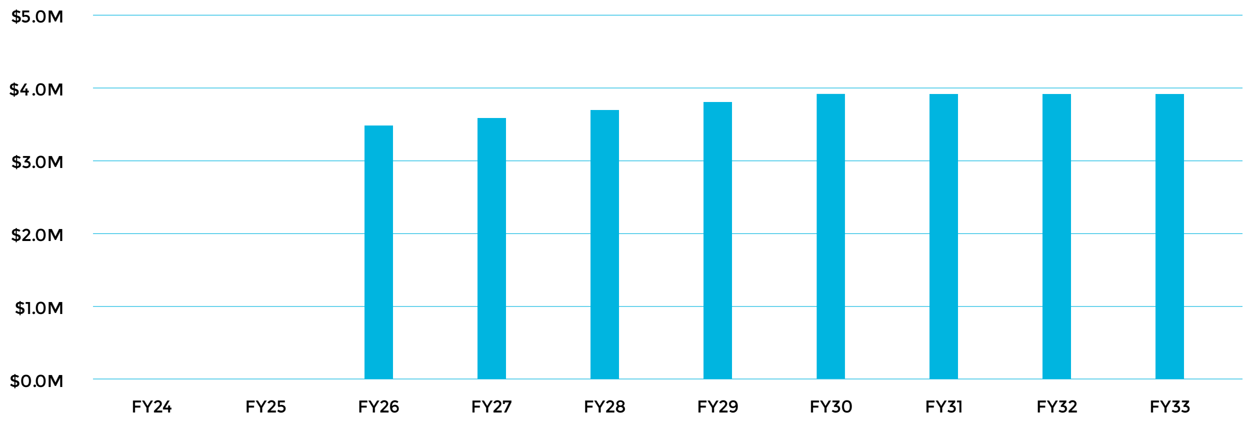


FIGURE 12.36: FORECAST CAPEX – DISTRIBUTION SYSTEMS

12.8 Protection and control

This Section describes our protection and control fleet and provides a summary of our associated asset management practices. The protection and control fleet comprise the following five subcategories:

- Protection systems
- Transformer management systems
- Communications systems
- Automation systems
- Power quality metering

12.8.1 PROTECTION SYSTEMS

Protection relays are devices that form a major part of the protection system. These are crucial for the safe and reliable operation of the electrical network. The protection relays detect faults and isolate the faulted network parts from the electrical network whilst retaining the healthy part of the network in service. This allows Vector to minimise the number and extent of power outages to customers.

Vector uses a variety or protection relays as discussed in the sections that follow. Failures of protection relays are rare but they have a shorter design life than the primary equipment they protect. Additionally, the legacy electro-mechanical relays within the network are at risk of obsolescence, with limited manufacturer support and spare parts availability. The failure of protection relays in detecting and clearing faults can potentially result in catastrophic plant damage, cascade network damage and in rare instances, injury or death to persons. As such, the effective monitoring of asset health and flexible designs to allow for asset replacement, is highly important for this asset class.

12.8.1.1 FLEET OVERVIEW

Vector has approximately 3,300 protection relays in service within the network. They are installed within GXPs, zone substations, and distribution assets to isolate and clear faults that could otherwise damage network assets or cause harm to the public. Vector use three types of relays:

- Electromechanical
- Numerical
- Static

Table 12-33 provides a summary of the relay types in the fleet. This shows that the majority of protection relays in Vector's network are numerical relays.

ELECTROMECHANICAL	STATIC	NUMERICAL
673	76	2,523

TABLE 12-33: SUMMARY OF RELAY TYPE COMPOSITION

12.8.1.2 POPULATION AND AGE

The population and age profile for electro-mechanical, numerical and static relays are provided in Figure 12-37 below (Vector notes that the level of data accuracy is approximately 96%)

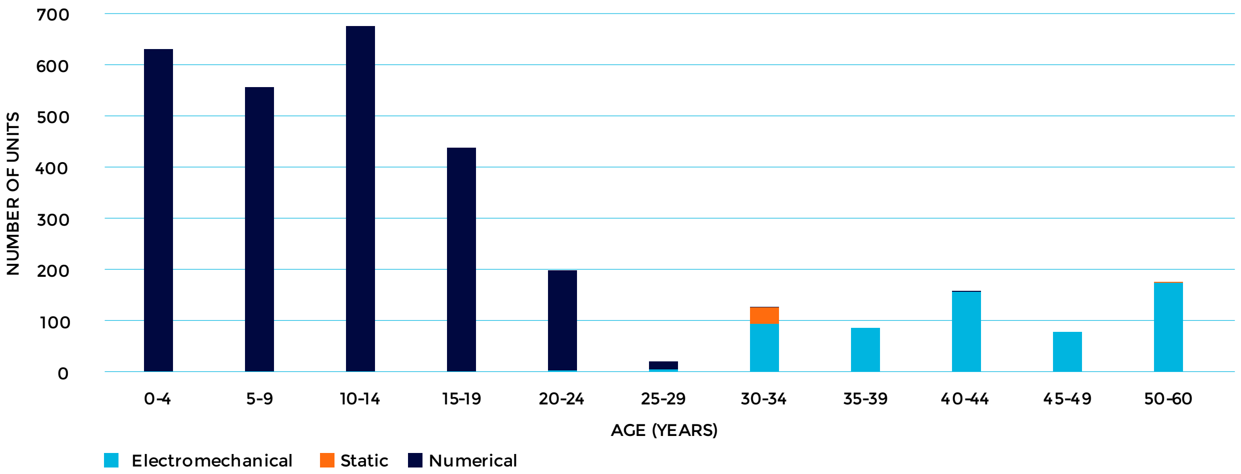


FIGURE 12.37: PROTECTION RELAY FLEET AGE PROFILE BY TYPE

12.8.1.3 CONDITION AND HEALTH

As protection relays reach their design life, their failure rate is expected to increase. Most relay failures on Vector's network since 2013 have been due to failure of an aging asset. Vector has programmes of work in place to replace existing electromechanical, static and first-generation numerical relays with modern numerical relays.

Electromechanical relays are reliable but is an aging legacy protection technology at risk of obsolescence and with only basic functional settings and data storage capability which prohibits fault and event analysis. They also have no relay supervision functionality. It is becoming increasingly costly to obtain spare parts and retain the skills required to maintain and operate this fleet. Approximately 20% of the relays are electromagnetic. The oldest are 50 to 60 years old.

Static relays are solid state devices with no moving parts, are easy to configure and more flexible compared with electro-mechanical relays. However, they are limited in their functionality when compared with numerical relays and lack event recording facilities. Static relays are also becoming obsolete, spare parts are becoming harder to source and more expensive; there are also reliability issues associated with this type of relay. The static type relays on Vector's network are 30 years old.

Numerical relays are extremely flexible as they are programmable and can be configured to perform a wide range of protection functions. They can store data and be used for post fault event analysis. They are also equipped with digital communication functionality and can be integrated directly with the SCADA system. The disadvantages of these relays include a relatively short 20 year design life as they use microprocessor-based technology and the need to manage firmware versions and compatibility requirements. Currently, more than half of the relays within Vector's network are of the numerical type and are less than 15 years old. To date, failures of numerical relays have been rare.

12.8.1.4 MANAGEMENT STRATEGY

Vector's long-term asset management strategy for protection relays is to progressively phase out static, electromagnetic and first-generation numerical relays and replace them with modern numerical relays within the next 10 years. The replacement activities will prioritise electromagnetic relays on rural overhead feeders and high load substations, followed by the remainder of the static relays. The risk of relays will be reassessed annually, and the replacement activities are reprioritised as required.

The superior monitoring and control capabilities provided by the modern numerical relays provide better visibility and control to the network. This will allow Vector's network to deliver higher reliability and resilience. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.1.5 DESIGN AND CONSTRUCT

All new relays on Vector's network will be the of numerical type and will take into consideration the relay being replaced at least once during its design life. This replacement must be seamless through flexibilities allowed during the design stage. Vector has rationalised to two relay manufacturers; Siemens and SEL (Schweitzer Engineering Laboratories). This standardised approach reduces the number of relay variants and the number of spares held and introduces familiarity with the programmable logic used in the relays, the firmware and setting software. The standardised relay approach combined with standardised wiring designs decreases the duration of network outages for installations.

12.8.1.6 OPERATE AND MAINTAIN

Vector's maintenance requirements for protection relays are detailed in ESM801. FSPs undertake the following general inspection and maintenance activities:

- Investigate and repair or replace any faulty devices and associated systems showing signs of imminent failure or damage.
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards.
- Maintain general cleanliness of the devices due to build-up of dust or grime.
- Investigate and remediate a device that has powered down or indicates abnormal alarms.
- Arrange a replacement of a relay that has failed the self-test.

12.8.1.7 REPLACE, RENEW AND DISPOSE

Replacement prioritisation for Vectors investment programme include the following considerations:

- Imminent relay or protection system failure.
- Relay spares availability
- Reliability concerns (based on performance of particular models)
- Data storage and fault recording capability, grading limitations and type of connected load.
- Feeder automation program
- Live line works implementation (Health and Safety)

12.8.2 TRANSFORMER MANAGEMENT SYSTEMS

Vector employs Transformer Management Systems (TMS) to monitor zone substation power transformers, manage their performance and predict failure. TMS systems are used to monitor supply voltage quality to ensure compliance with regulatory standards. TMS within Vector's network range from legacy electromechanical relays, older generation programmable logic relays to modern numerical relays. A failure of TMS relay could potentially result in Vector's primary assets operational integrity being compromised, its performance to deteriorate, or creating undue risk to equipment.

12.8.2.1 FLEET OVERVIEW

Vector has 212 TMS relays in service. These devices can be grouped into four major types as listed below:

- Numerical TMS relays
- Static TMS relays
- Programmable Logic Controller (PLC) TMS
- Electromechanical TMS relays

Table 12-34 below provides a summary of TMS fleet. This shows approximately 78% of the TMS fleet are modern numerical types.

ELECTROMECHANICAL	STATIC	PLC	NUMERICAL	TOTAL
20	26	3	163	212

TABLE 12-34: TMS RELAY FLEET COMPOSITION

12.8.2.2 POPULATION AND AGE

The population and age profile for electro-mechanical, numerical, PLC and static TMS relays are provided in Figure 12-38 (Vector notes this data has an error rate of approximately 3%):

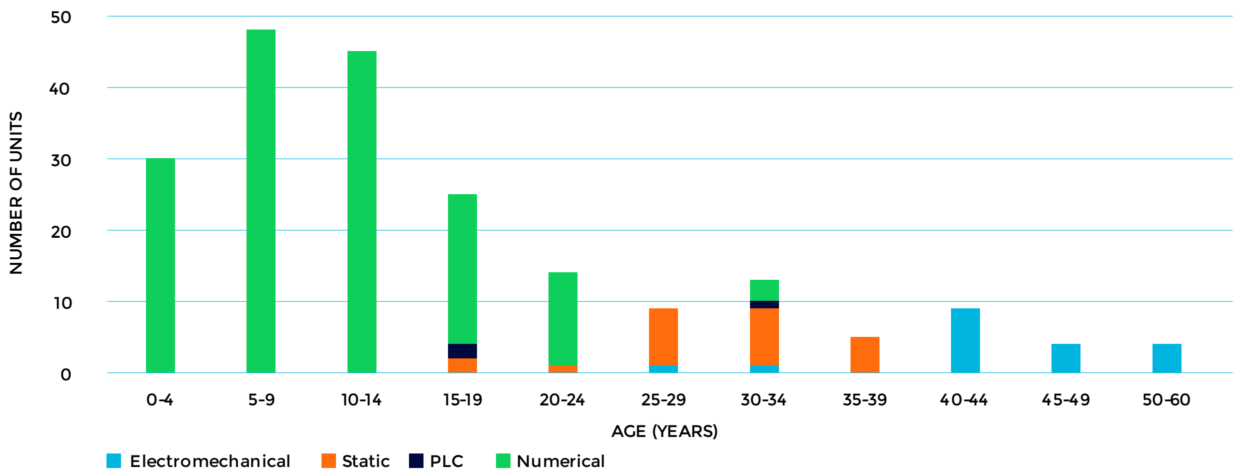


FIGURE 12.38: TMS RELAY FLEET AGE PROFILE BY TYPE

12.8.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The majority of the modern numerical TMS relays on the network are within their design life of 20 years, hence failures are rare.

The PLC based TMS and Static TMS Relays on the network are between 17 and 31 years old. They are approaching the end of their design life and are most susceptible to failures. There is a trend of increasing failures over the past few years associated with PLC based TMS and Static TMS relays. Additionally, technical support from the manufacturers is limited for these types of relays and not many field crews are versed with the ladder logic used in these relays. The systems with high failure rates and known issues are being actively monitored and are prioritised for replacement with modern numerical TMS relays.

The age of the electromechanical TMS relays range between 28 and 51 years. While most are still functioning satisfactorily, they are at risk of obsolescence with limited spare parts and technical support available from manufacturers. They also require regular calibration that adds cost and consumes technician resources. Vector is in the process of replacing the aging electromechanical TMS relays with modern numerical TMS relays.

12.8.2.4 CONDITION AND HEALTH

Over the past 5 years, the use of modern numerical TMS relays on Vector's network has increased from 63% to 77%. Modern numerical relays within Vector's network are well within their design life of 20 years hence are considered to be highly reliable and in good working condition.

The PLC based TMS and Static TMS relays have the highest failure rate over the last few years. They are also at risk of obsolescence with limited spares availability.

12.8.2.5 MANAGEMENT STRATEGY

The management strategy for TMS is based on asset age, risk of obsolescence and reliability. It is informed by asset health data being collected from our SCADA and supplemented with information gathered by our field service providers and industry peers (such as other utilities). The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.2.6 DESIGN AND CONSTRUCT

The replacement of the TMS units will reuse existing control wiring as well as the enclosures (cabinets) where practicable. Vector has standardised on two types of TMS relays; REGSys and Schweitzer. New switchboards will incorporate REG-DA relays (from REGSys), while retrofit projects will have either REG-DA or SEL-2414 (Schweitzer) relays.

12.8.2.7 OPERATE AND MAINTAIN

Vector's maintenance requirements for protection relays are detailed in ESM801. The Field Service Providers undertake general inspections of the relays as follows:

- Investigate and repair or replace any faulty devices and associated systems that is mal-operating or has physical damage.
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards.
- Maintain general cleanliness of the devices due to build-up of dust or grime.
- Investigate and remediate a device that has powered down or indicating abnormal alarms.
- Arrange a replacement of the TMS or relay that has failed the self-test.

12.8.3 COMMUNICATIONS SYSTEMS

Vector uses communication systems to enable real time control, monitoring, management and restoration of the power network. The communication systems include:

- Backhaul communication network that links the remote equipment to the centralised control and monitoring system

- Onsite communication network interfaces with the equipment on site to the Backhaul communication network

12.8.3.1 FLEET OVERVIEW

The backhaul communication network used for substation connectivity includes:

- **Fibre network** used by over 80% of zone substations and GXP's for the backhaul communication system.
- **Pilot cables** used as the communications medium for telecommunications between substation sites
- **Digital Microwave Radio (DMR)** network that uses 3G where fibre connectivity is unavailable.
- **Third party networks** comprising cellular, fibre, wireless and radio network, that are employed when the fibre network becomes unavailable.
- **Legacy Communication Network** comprising aged and obsolete equipment that remains in service but is due for replacement in the near future.

The voice communication system within Vector's network comprises:

- **VHF & UHF radio systems** that enable communication between field crews and the EOC.
- **Substation IP Telephony** that provides voice communication between a zone substation and the EOC.
- The on-site communication systems that utilise the backhaul communication network to interface/communicate with end devices employed by Vector which includes the following:
- **Routers**
- **Network Switches**

Table 12-35 provides a summary of the numbers of communications devices.

CISCO ROUTERS	ETHERNET SWITCH	CELLULAR ROUTERS
165	402	650

TABLE 12-35: NUMBERS OF ROUTERS AND SWITCHES

12.8.3.2 POPULATION AND AGE

Backhaul communication system consists of many thousands of lines and it is not practical to compile age profiles and key statistics table. The voice communication system also doesn't have age profiles or a key statistics table at the time of writing this document.

The population and age profile for Cisco Routers are provided in Figure 12-39 below:

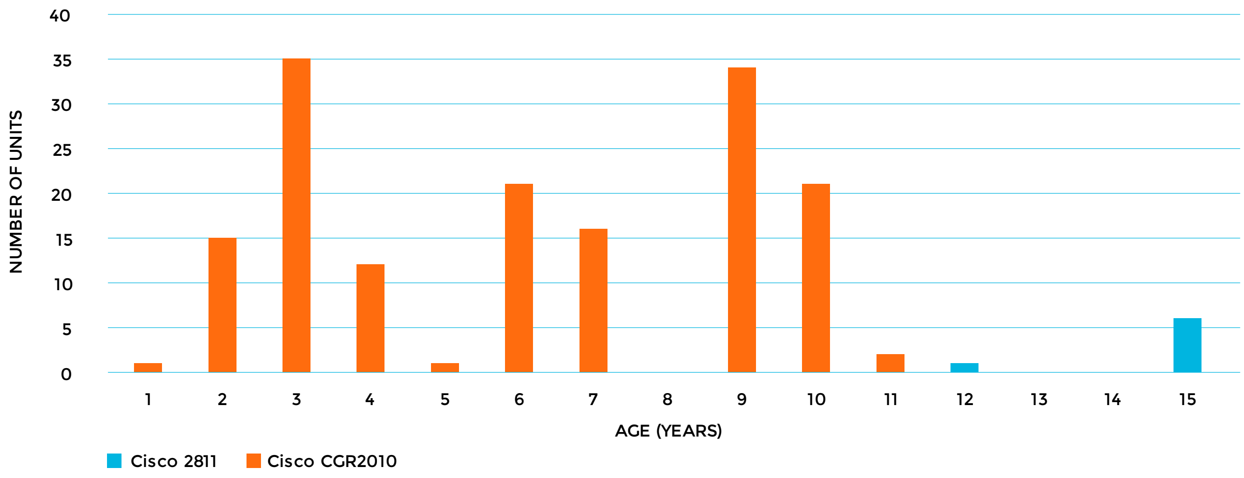


FIGURE 12.39: CISCO ROUTER FLEET AGE PROFILE

The population and age profile for Ethernet Switch are provided in Figure 12-40 (Vector notes this data has an error rate of approximately 2%):

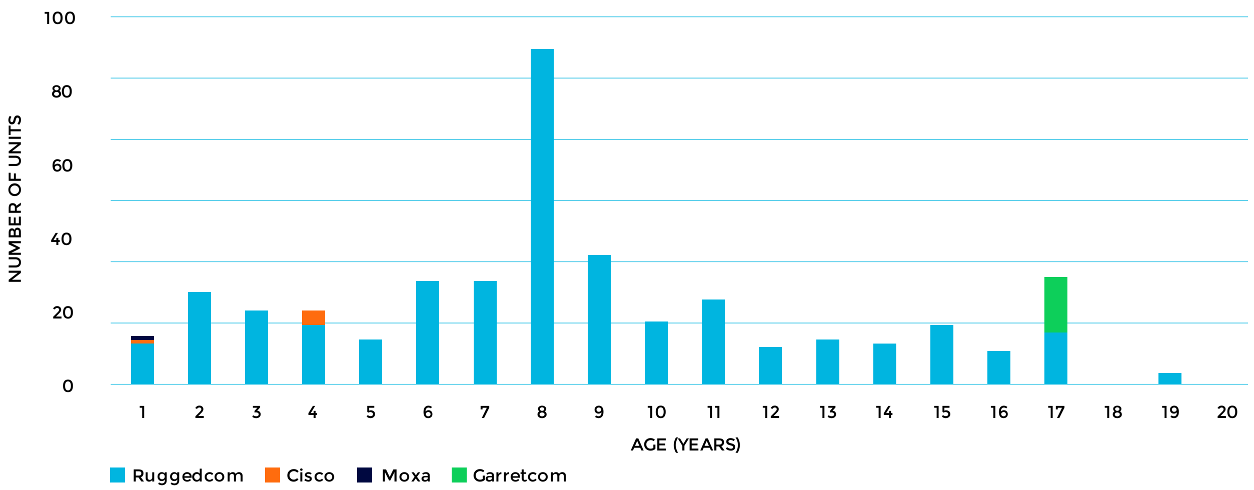


FIGURE 12.40: ETHERNET SWITCH FLEET AGE PROFILE

The population and age profile for Cellular Router are provided in Figure 12-41 below (Vector notes this data has an error rate of approximately 0.5%):

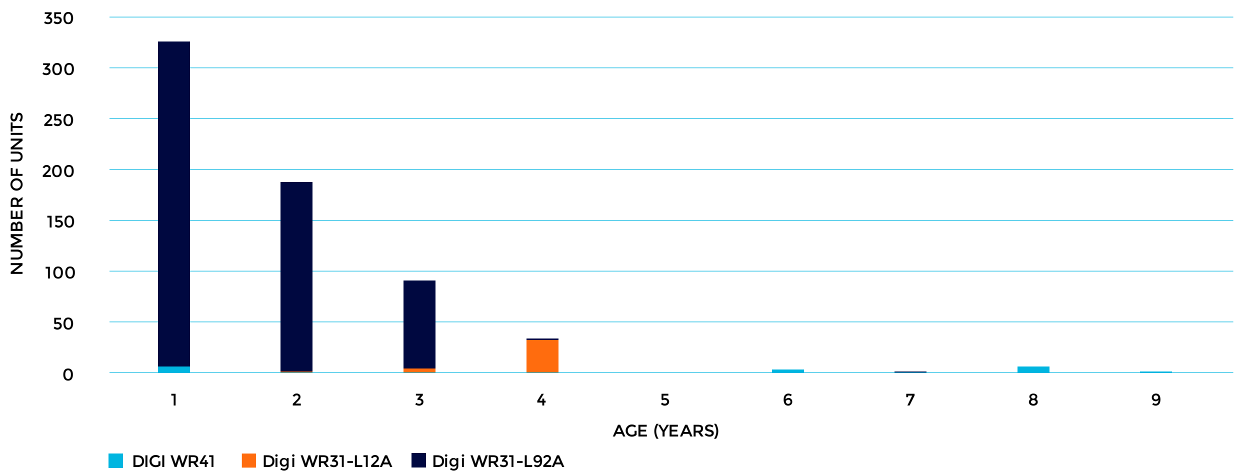


FIGURE 12.41: CELLULAR ROUTER AGE FLEET PROFILE

12.8.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

For fibre infrastructure as part of the Backhaul communication systems, the system availability figure for the last year has been above the 99.95% availability target. The fibre outages experienced are more often caused by third parties rather than equipment failures. The fibre network is fit for purpose and has been extensively expanded over the last few years and will continue as required. A small number of zone substations still make use of copper pilot cables to serve areas where fibre optic communications are not available or to support older protection-based technology. The available bandwidth on the fibre network is sufficient for future expansion. The performance of the DMR system is not actively monitored. Real time remote monitoring functionality will be implemented in the future to provide performance information. The key risks associated with DMR are environmental and third-party damage.

The voice communication system's performance is not actively monitored. Performance information from third-party infrastructure (e.g. repeater stations) will be collected in the future to help formulate voice communication asset strategies. They key risk associated with the radio communication system is the reliance on third-party infrastructure which could cause loss of communications should there be failure of the third-party infrastructure. The substation IP Telephony relies on infrastructure such as routers, which could potentially cause a communications outage.

The Cisco routers and Ruggedcom switches have an achieved availability figure above the 99.95% target over the past year.

12.8.3.4 CONDITION AND HEALTH

The asset health of the fibre infrastructure for backhaul communications is good. The DMR equipment are also in healthy state but is approaching the end of its design life.

The voice communication radio systems are up to 30 years old and is of average to poor health due to its advanced asset age. The substation IP telephony system is in good condition, however the analogue telephones installed at 13 sites are becoming obsolete and will be progressively replaced with the more modern VoIP telephones.

12.8.3.5 MANAGEMENT STRATEGY

Vector is progressively replacing copper pilot cables with fibre cables for the backhaul communications network to cater for the bandwidth and reliability required for the future energy network. The DMR system provides a network that is highly available and has sufficient spare capacity for future expansion. This system is expected to be in operation for the foreseeable future with its functionality integrated into Vector Fibre's network management system. The legacy networks such as OTN, PDH etc. are obsolete, and Vector is struggling to retain expertise to operate and maintain these systems. They will be either migrated into modern network or retired if no longer required. Vector will continue to replace the remainder of the Cisco 2811 routers that are approaching end of life and unsupported. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.3.6 DESIGN AND CONSTRUCT

For the Backhaul Communications Network, the following must be considered when designing and constructing new infrastructure:

- Provide a secure, highly available communication link to remote sites like zone substations, GXP's etc.
- Ensure that a failure of a single communications node does not impact multiple sites.
- The infrastructure to provide real time monitoring and control capabilities to manage Vector's electricity network.

A support & maintenance agreement is in place for the fibre infrastructure, and DMR equipment will be procured and spares maintained for fault restoration purposes.

On site network equipment will be standardised as much as possible to reduce the number of spares required to be kept.

The Cisco Grid Series routers and Ruggedcom ethernet switches are Vector's standard devices across all substations. Strategic spares are kept for zone substations.

12.8.3.7 OPERATE AND MAINTAIN

Fibre

The fibre infrastructure for the SCADA network is managed by Vector Fibre.

Digital Microwave Radio (DMR)

The maintenance requirements for the DMR system are defined in Vector's standard ESM805. These include:

- Annual off-site inspection (remote monitoring) with corrective follow-up on remedial actions as required.
- Annual on-site inspection with corrective follow-up on remedial actions as required.
- Two yearly on-site testing with corrective follow-up on remedial actions as required.

VHF radio

Where maintenance of radio equipment is required, site specific maintenance standards are developed (ESM805 Maintenance of Radio Equipment, ESM709 Penrose – Hobson Tunnel Radio Systems and ESM712 Penrose – Hobson Tunnel Radio Systems.)

Substation IP Phones, Routers and Ethernet switches and Cellular routers

There are no maintenance requirements for the IP Phones, Cisco routers or cellular routers. This equipment is monitored and managed by Vector Fibre under their support agreement.

12.8.4 AUTOMATION SYSTEMS

Vector employs network automation systems, comprising substation RTUs and distribution controllers, to provide real-time remote presence at locations throughout the network and enable automation of key processes such as monitoring plant status and service restoration. Vector has adopted an internationally recognised open communications architecture standard that allows different devices located within the zone substations to integrate seamlessly and communicate with the SCADA system through the communications network.

12.8.4.1 FLEET OVERVIEW

Vector has 653 RTU devices from a variety of suppliers within its network. Table 12-36 below provides a summary of RTU types.

TYPE	NUMBERS
ABB	189
Abbey Systems	10
AdvanceTech	2
Foxboro	60
Fuji Electric	8
GTP Plessey	16

TYPE	NUMBERS
Leads & Northrup	1
Linak	1
Mitsubishi Electric	1
SEL	345
Siemens	12
Unknown	8

TABLE 12-36: RTU FLEET COMPOSITION

Table 12-37 below provides a summary of distribution automation devices type composition.

DEVICE TYPE	TOTAL NUMBER
Voltage Regulator Devices	4
Customer DC System Monitoring	3
FPI	3,918

TABLE 12-37: DISTRIBUTION AUTOMATION DEVICE COMPOSITION

12.8.4.2 POPULATION AND AGE

The majority of automation devices range in age from new to over 12 years, with the odd exceptions that were installed in 1988.

The population and age profile of Vector's fleet of automation devices are provided in Figure 12-42 below (Vector notes this data has an error rate of approximately 18%):

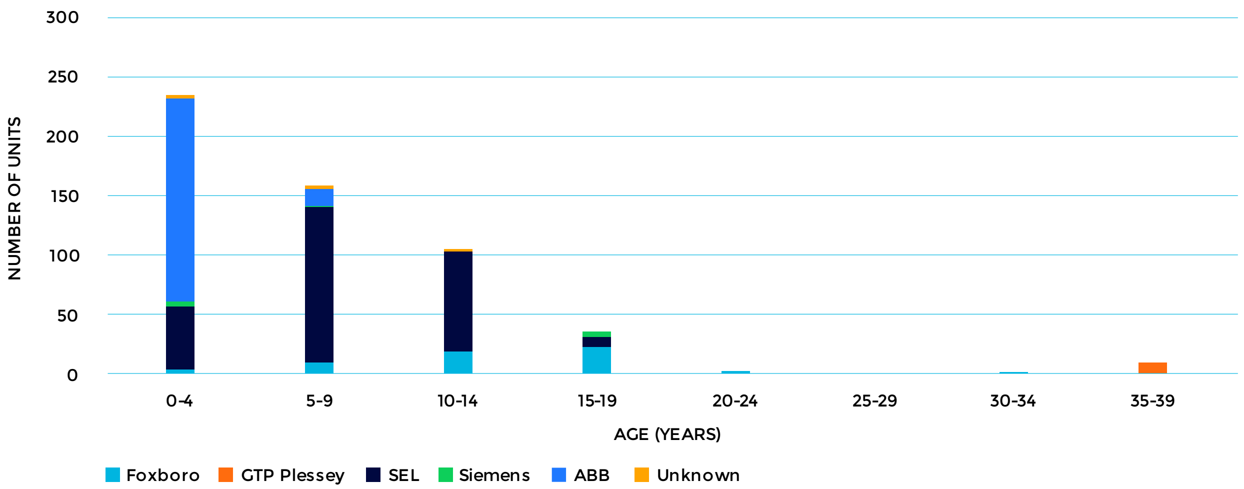


FIGURE 12.42: NETWORK AUTOMATION SYSTEM AGE PROFILE

12.8.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The introduction of distribution automation infrastructure has clearly demonstrated the benefits of network visibility afforded by these systems. Reliable and accurate visibility of our network is critical when making real time operational decisions and responding to outages. In addition, the implementation of automation systems allows hands-off operation of the network and reducing the need for crews to travel, with its associated hazards and time to navigate congested roads, to remote destinations.

Whilst the loss of an RTU may not be an immediate issue under healthy network conditions, the loss of visibility under abnormal or fault conditions can result in overloaded networks, delayed fault restoration and, most importantly, lack of response to safety risk events.

Vector maintains its capability to operate and maintain RTU's and distribution automation devices across multiple generations of underlying hardware platforms. The current core capability of Vector's Distribution Automation system is sufficient to operate the network now, but it is evident that additional capability and performance will be required as the industry develops, and Vector has to adapt to the needs of our customers.

12.8.4.4 CONDITION AND HEALTH

Due to the age of Vector's legacy RTU equipment, some of the components within the RTU are no longer manufactured and/or supported by the OEM. Therefore, a portion of the RTUs within Vector's fleet, especially those installed in the 1980s and early 1990s, are considered to be obsolete. In addition, better technology is required to ensure the network can accommodate higher levels of volatile generation and unpredictable loads. The technology used by the old generation of RTUs cannot cope with new demands. Since 2012 Vector has systematically replaced legacy devices as part of switchgear and protection replacement projects and as stand-alone RTU replacement projects.

In general, the modern RTU devices within Vector's network have been operating reliably and improves safety by providing network visibility and control that allows remote operation.

12.8.4.5 MANAGEMENT STRATEGY

Replacement of RTU devices in Vector's network is based on the level of functionality, the technology and the availability of spare components rather than any measurable condition points.

The existing infrastructure has been architected so it can expand to accommodate the anticipated service, traffic and interface growth. The following strategy is adopted by Vector for RTUs:

- Replace on failure – cut spending to a minimum and accept a progressive decline in performance and increasing risk
- "BAU" – no investment beyond maintaining current capability, migration to current standard on major site-works only and resolving any significant issues
- Invest in achieving a common base platform across the SCADA fleet, removing the obsolete plant that is still in service but presenting progressively higher risk

The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.4.6 DESIGN AND CONSTRUCT

The automation infrastructure provides operational services to the SCADA system. The infrastructure needs to be designed with the following in mind:

- Provide a secure environment in which the automation equipment can operate
- Provide infrastructure which allows efficient development of data acquisition and control services
- Utilise robust infrastructure installations to support high service performance
- Provide robust DC systems with adequate backup supply suitable for the prolonged loss of AC mains
- Provide adequate capacity for present and future needs

Vector has standardised RTU designs that use devices from approved manufacturers to reduce the number of spares required thereby minimising the total cost of ownership.

12.8.4.7 OPERATE AND MAINTAIN

Vector's maintenance requirements for RTUs are specified within ESM801.

FSPs will undertake the following general inspections of RTUs:

- Investigate and repair or replace any faulty devices and associated systems or damaged units.
- Fix any wiring or mounting of the device that is unsecured or damaged that poses electrical failure risks and safety hazards.
- Maintain general cleanliness of the devices due to build-up of dust or grime.
- Investigate and remediate a device that has powered down or indicating abnormal alarms.
- Arrange a replacement of the RTU or relay that has failed the self-test.

12.8.5 POWER QUALITY METERING

Vector's power quality meters (PQMs) are intelligent revenue class devices that provide power quality analysis coupled with revenue class accuracy, communications and control capabilities. They are deployed at key distribution points such as GXPs and zone substations. These meters communicate to the metering central server over an IP communication network. Power quality information and energy consumption metrics are required to make informed decisions that best meet the business objectives as well as to meet legal and regulatory requirements. At the GXP level PQMs provide the function of "check meter" to compare electricity consumption against revenue metering measurements. PQMs are also used to initiate interruptible load via the ripple systems to reduce peak demand. Their event data storage functionality is also used for post fault analysis and power quality excursions.

12.8.5.1 FLEET OVERVIEW

Vector has 142 power quality meters commissioned on its sub-transmission and distribution networks. Vector uses two types of PQM spanning multiple generations:

- Advanced functionality PQM: ION 7700, ION 7600, ION 7650 v3XX, ION 7650 v400, ION 92040
- Intermediate: functionality PQM: ION 7330, PM 8000, ION 7400

Advanced PQM's are typically deployed at Transpower GXP's and zone substations, while intermediate PQM's are deployed on distribution feeders.

Table 12-38 summarises the PQM fleet.

TYPE	NUMBERS
ION7330	5
ION7400	11
ION92040	5
ION7600	2
ION7650 V3xx	57
ION7650 V4xx	57
ION7700	2
PM8000	3

TABLE 12-38: PQM TYPE COMPOSITION

12.8.5.2 POPULATION AND AGE

The population and age profile for PQMs are provided in Figure 12-43 below:

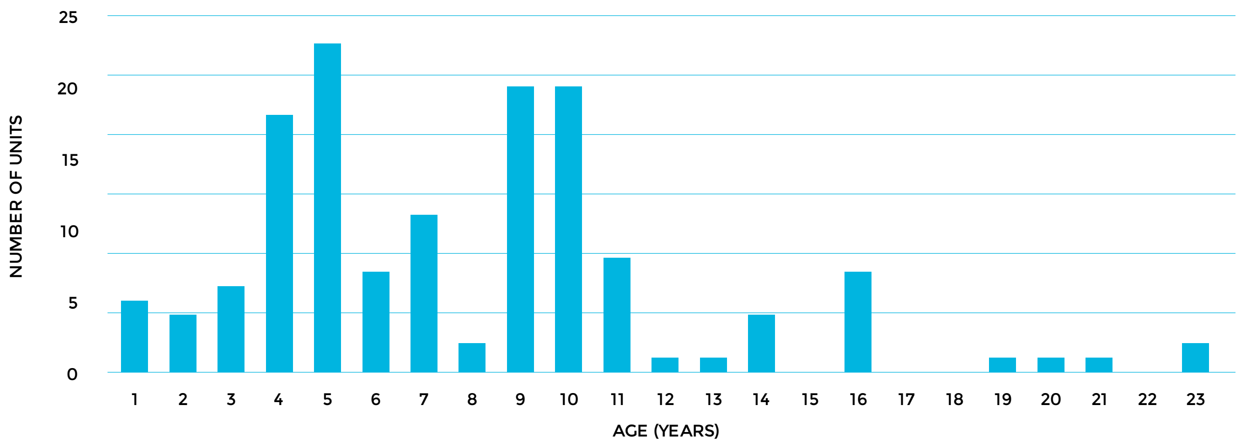


FIGURE 12.43: PQM FLEET AGE PROFILE

12.8.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

The PQM's currently in service are in good health, despite the age of some devices. All PQM's within the network are equipped with self-monitoring capabilities. However, older versions of devices are running on unsupported software and devices that are getting close to or exceed their design life of 15 years will be included in the replacement programme.

Key risks involving PQM devices are communications and hardware failure. The PQM field devices have a 30-day data storage capability that mitigates the risk of data loss. Further, the communications to all zone substations have dual redundancy which provides a high level of reliability.

12.8.5.4 CONDITION AND HEALTH

The power quality metering devices in service operate reliably even though some of these devices are reaching the end of their design lives. These devices have in built self-supervision functionality and provide remote monitoring and recording functionality for post event analysis. Replacement devices are obtainable from a selected New Zealand-based supplier.

12.8.5.5 MANAGEMENT STRATEGY

Vector is progressively replacing older (15 years or over) models of the PQM fleet to ensure a fleet is in place that will have technical support of the hardware as well as software support from the vendor. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.8.5.6 DESIGN AND CONSTRUCT

The PQM system must be designed with the following considerations:

- Utilise robust infrastructure installations to support high service performance
- Provide adequate capacity for present and future needs
- Provide infrastructure which allows efficient development of communications services

12.8.5.7 OPERATE AND MAINTAIN

The PQM hardware is digital and has no field serviceable parts and does not require physical maintenance. The PQM Software and hardware are monitored and supported by Vector's service representative as part of a support agreement.

12.8.6 REPLACE, RENEW AND DISPOSE

12.8.6.1 PROTECTIONS SYSTEMS

The electromechanical, static and first-generation numerical relays within Vector's network are coming to the end of their expected service lives. Many will remain in operation but are planned to be replaced with numerical relays within the next 10 years. The replacement of relays will be prioritised based on the following risks:

- Imminent relay or protection system failure
- Spares availability
- Reliability concerns, i.e. increasing failure of relays of a particular model
- Fault record capability, grading limitation and type of connected load

12.8.6.2 TRANSFORMER MANAGEMENT SYSTEMS

The main drivers for the replacement of transformer management systems are age, risk of obsolescence and reliability. Vector's approach is to replace the PLC based units and Static TMS relays followed by electromechanical TMS relays and other TMS devices that are more than 20 years old. The replacement projects are prioritised as follows:

- Replacement of all PLC based systems (over the next 2 years)
- Replacement of failing static devices (within 5 years)
- Replacement of all electromechanical devices (within 10 years)

12.8.6.3 COMMUNICATIONS SYSTEMS

The main drivers for the replacement of Vector's communications systems are age, risk of obsolescence and reliability. Vector is in the process of replacing its legacy network that remains in service but no longer has manufacturers' support and inhouse expertise.

12.8.6.4 AUTOMATION SYSTEMS

The main drivers for the replacement Vector's automation systems are age, risk of obsolescence and reliability. The specific criteria for RTU replacement are:

- Substation primary equipment, such as the switchboard, is being replaced with modern equipment. The RTU will be replaced with either an IED or modern RTU to enable improved facilities, such as Ethernet connection and remote engineering connection to equipment, and to reduce the small wiring required to install the switchboard and therefore reduce installation costs.
- Lack of strategic spares available for ongoing maintenance of the remaining RTUs.
- To support improved functionality such as for IEC61850.

12.8.6.5 POWER QUALITY METERING

The main drivers for the replacement of legacy PQMs are obsolescence and lack of ability to upgrade software on older models. The availability of spares will help prolong the asset life of existing PQMs although not indefinitely as both the PQMs and spares are already in an aged condition and is not compatible with software updates. Where practicable, PQMs are replaced as part of other capital projects such as switchgear replacement.

12.8.7 FORECAST SPEND

The forecast capex graph shown in Figure 12-44 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period. The replacement and refurbishment programme for protection system assets is described in detail in Section 12 Appendix and includes the proposed investment for each individual project.

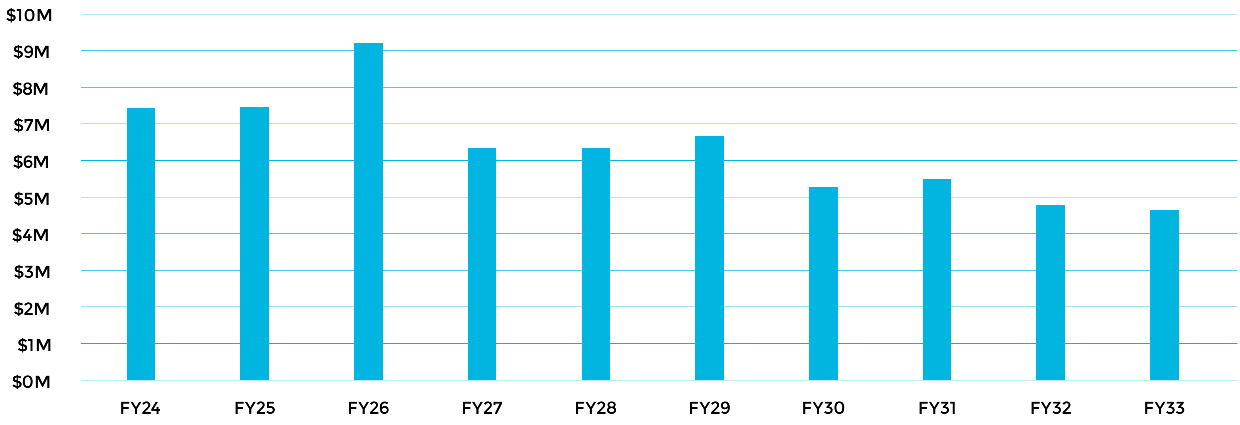


FIGURE 12.44: FORECAST CAPEX - PROTECTION CONTROL

12.9 Auxiliary systems

This section describes our auxiliary systems fleet and provides a summary of our associated asset management practices within the following subcategories:

- Power supply systems
- Load control systems
- Capacitor banks
- Security and access systems
- Fire protection systems
- Earthing systems

12.9.1 POWER SUPPLY SYSTEMS

Auxiliary power systems provide power to secondary systems in zone and distribution substations including protection, control, automation, metering and communications equipment. Typically, this equipment operates at 110, 48, 24 or 30 V DC and is critical for the safe and reliable operation of a zone substation and its primary function of customer power supply. DC battery banks are charged by LV AC chargers and ensure that in the event of a LV AC system failure, the DC battery bank supplies these critical secondary systems for a period sufficient to re-establish LV AC supply. At zone substation critical sites, DC systems are fully redundant to provide resilience and minimise disruption when maintenance activities are undertaken.

12.9.1.1 FLEET OVERVIEW

Key statistics of the DC charger assets are shown in Table 12-39.

TYPE	NUMBERS
110 V DC chargers	230
48 V DC chargers	2
30 V DC chargers	24
24 V DC chargers	156
12 V DC chargers	232

TABLE 12-39: DC CHARGER FLEET OVERVIEW

The 110 V DC systems are used to provide power to protection relays and DC secondary systems within switchgear. The 48 V DC and 24 V DC systems are used to supply power to the communications and digital radio systems respectively. The 30 V DC systems exist in zone substations with legacy communications equipment and legacy circuit breakers with 30 V equipment. These are being progressively replaced with 110 V DC and 48 V DC systems as part of a wider risk-based replacement strategy for the legacy communications equipment and legacy circuit breakers.

12.9.1.2 POPULATION AND AGE

Based on Vector's experience, the expected age of reliable operation for a DC charger is around 15-20 years. The age distribution for each voltage type of DC charger is shown in the chart below. Due to incomplete installation date records, Vector notes this data has an error rate of approximately 33%.

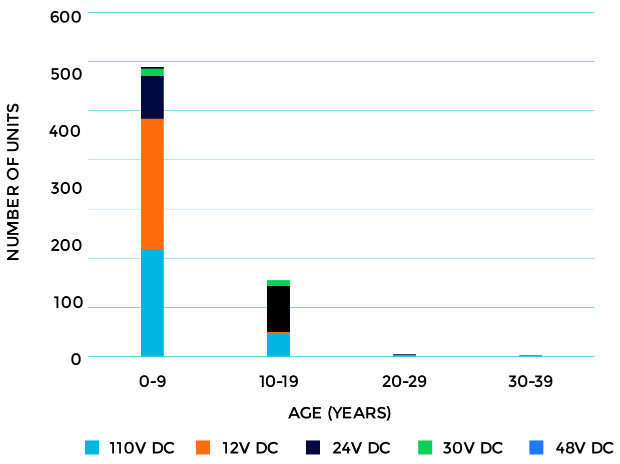


FIGURE 12.45: DC CHARGER FLEET AGE PROFILE

12.9.1.3 ASSET PERFORMANCE, EMERGING TRENDS, AND RISKS

A large planned programme to replace DC chargers over the last few years has ensured that Vector's DC systems are continuing to perform in line with expectations and there have been no recent failures leading to an unplanned loss of supply.

12.9.1.4 CONDITION AND AGE

Age can be used as a proxy for the condition of DC systems. The average asset age of our DC systems is 15-20 years. Vector manages the condition of its DC systems using its inspection and testing regimes. Our 110 V DC systems also employ a Sentinel monitoring system which provides real-time monitoring on each discrete battery (monobloc): temperature, impedance and voltage. This approach has proven successful in replacing assets prior to systemic failure.

12.9.1.5 MANAGEMENT STRATEGY

The management strategy for auxiliary systems is based on asset health, risk of obsolescence, reliability, and safety. It is informed by asset health data which is being continuously improved with information gathered by our field service providers. The following sections describe how Vector is managing this asset class through the key lifecycle phases.

12.9.1.6 DESIGN AND CONSTRUCT

Vector has standardised its secondary systems on its switchgear to be powered using 110 V DC across all zone substation sites. Some sites still have legacy 24V DC and 30 V DC and are being progressively replaced due to condition or through planned site refurbishment. Vector continues to test the benefits of new technologies such as the use of Lithium-Ion batteries.

For the procurement of new DC systems, Vector utilises its specifications ESE-601 and END-6001.

12.9.1.7 OPERATE AND MAINTAIN

For real time visibility and monitoring of our DC systems, Vector has installed a Sentinel monitoring system at each of its zone substations. This provides real-time measurements and alarms to the engineering SCADA team to then generate any fault-correction response required by our FSP's.

Vector's maintenance standards for DC systems are outlined in the ESM601 maintenance standard. Planned maintenance activities are summarised below in Table 12-40.

ACTIVITY TYPE	ACTIVITY DETAIL	FREQUENCY
Inspection	Inspection on AC circuitry, fittings, main boards, network LV supply, auto changer over panel, meter panel, UPS	2 Months
Inspection	Thermovision inspection on all electrical equipment	1 Year
Functional Testing	Functional DC system testing on batteries, battery chargers, DC circuitry, UPS , fittings	4 Months
Inspection	Full DC system testing on batteries, battery chargers, DC circuitry, UPS, fittings and convertors	2 Years

TABLE 12-40: PLANNED MAINTENANCE ACTIVITIES FOR DC SYSTEMS

Vector follows internationally recognised standards such as AS2676, IEC 60050 and IEEE 1188 for the testing of its DC systems to ensure that best practice are adhered to in the management of its DC systems. Inspection and test results are uploaded to the SAP planned maintenance module by the FSP.

Minor items are addressed as corrective maintenance. Defects unable to be addressed as corrective maintenance are recorded within Vector's Active Risk Management system (ARM), along with assigned controls and action plans for a project-based resolution.

12.9.2 LOAD MANAGEMENT SYSTEMS

12.9.2.1 FLEET OVERVIEW

Vector uses demand-side load management systems on its distribution network to offer non-instantaneous system capacity reserve to the wholesale electricity market, and to respond to national grid emergencies. The following sections relate to customer hot water heating load management.

Due to the separate legacy power board network philosophies at the time of installation, four types of signalling systems exist: 'ripple injection' over power lines in the Auckland network and parts of the Northern network as ripple injection, 'pilot wire', 'rotary' or Cyclo' systems. Customers in the Auckland network can sign up to a 'controlled' (lesser cost) time of use (TOU) tariff. This allows signalling of these customer's hot water cylinders to switch on or off, shifting Vector's network demand peaks for up to three hours continuously within a 24-hour period. This signalling equipment also switches streetlights on and off at dusk and dawn on behalf of Auckland Transport for the balance of their streetlights not yet converted to their new management systems.

The number of ICPs per type of hot water load control system is provided in Table 12-41.

ASSET SUBCLASS	NUMBER OF ICP'S	SYSTEM STATUS
Ripple	335,509	Active load management in Auckland region only
Pilot wire	142,715	No active load management
Rotary	39,257	No active load management
Cyclo	15,353	No active load management

TABLE 12-41: NUMBER OF CUSTOMERS PER HOT WATER CONTROL TYPE

12.9.2.2 POPULATION, AGE AND CONDITION

Vector's fleet of 32 ripple plant units are installed across twelve zone substations. The replacement of two new plants in 2021 has brought down the average age from 34 years to 22 years. Apart from the 2021 replacements, Vector fleet of ripple plants are approaching end of life.

12.9.2.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Recently the two Otahuhu zone substation ripple plant controllers failed and an HV inductor failed at Liverpool zone substation. Internal dielectric breakdowns of the capacitors used for the Managere East and Manukau plants have also recently occurred. Although these plants have been successfully returned to service, these events are typical symptoms of an ageing ripple plant fleet.

Although Vector's ripple plants are suspectable to age related failure modes, they are considered to be performing adequately. This is a benefit of ripple load management system architecture which can tolerate the loss of a ripple plant without the loss of customer hot water supply.

12.9.2.4 MANAGEMENT STRATEGY

The new Transpower Pricing Methodology (TPM) that takes into effect from 1 April 2023 replaces interconnection and HVDC charges with benefit-based charge and residual charges. This will effectively remove the economic incentive to manage regional coincident peak demand (RCPD) under the current TPM. In the past, hot water load control has played a pivotal role in managing the RCPD.

Vector has reviewed the viability of their hot water (ripple) load management system under the new TPS and have decided to progressively decommission it. Vector's load control capability will progressively reduce over time in a 'stepped' manner and in accordance with the scale of ripple plant being decommissioned.

12.9.3 CAPACITOR BANKS

12.9.3.1 FLEET OVERVIEW

Vector uses static capacitor banks to maintain voltage stability and power quality across the network. In total, there is 30 MVAr installed across four zone substation sites in the Auckland and Northern networks. A programme based on recent network system studies will provide an additional 45 MVar at a further five sites to ensure our voltage and frequency metrics continue to be achieved.

12.9.3.2 POPULATION, AGE AND CONDITION

The average age of Vector's capacitor banks are 22 years. The expected operating life is around 20 years. Capacitor banks installed in an indoor environment are typically in better condition than their outdoor equivalents as they are not prone to environmental issues such as corrosion and pollution.

12.9.3.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There is an increasing number of failures relating to capacitor banks as this asset class approaches end of life. The most common type of failure is internal bushing insulation breakdown, particularly for units installed outdoors.

Although failures have occurred, there have been no arc-flash incidents associated with ground mounted capacitor banks. Faulty units are automatically disconnected using internal fuses and circuit breakers. Our aged capacitor bank fleet is not fitted with arc-flash protection. If a replacement is required, the equipment will be procured with arc flash functionality to improve the safety of personnel.

12.9.3.4 MANAGEMENT STRATEGY

Vector uses its DigSILENT network modelling software tool to determine the need for capacitor banks in the network. Modelling results will show which capacitor banks can be removed from the network altogether or where new capacitor banks need to be installed. There are instances where capacitor banks already exist but have not been in use for some time: if modelling shows that the capacitor banks should be placed back in service, refurbishment will be undertaken depending on the condition of the capacitor banks.

Planned maintenance for capacitor banks are detailed in Vector's maintenance standard ESM603 and include on-site assessments such as visual and thermographic inspection and condition testing. Minor items are corrected as corrective maintenance. Defects unable to be corrected as corrective maintenance are recorded within Vector's Active Risk Management system, along with assigned controls and action plans for a project-based resolution.

Capacitor banks are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance activities.

12.9.4 SECURITY AND ACCESS SYSTEMS

12.9.4.1 FLEET OVERVIEW

Vector security and access systems at facilities consist of keyed and electromagnetic locks, door hardware, electric and perimeter fencing and access and monitoring systems. Cardax systems with card readers are used for access and monitoring and are installed across all zone substation sites and other critical sites such as Transpower GXPs and the Vector cable tunnel.

Vector EOC remotely monitors, via SCADA, the entrance and egress of facilities via the card reader. Motion detectors are fitted to detect intruders in switch room buildings. If an unauthorised entry event alarm occurs, the EOC contacts the FSP to investigate. If required, the Police are contacted.

12.9.4.2 POPULATION, AGE AND CONDITION

Vector has recently completed an upgrade to install Cardax systems to replace end of life control units installed in the 1970s. There are 147 units installed across the network.

12.9.4.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

There have been no recorded failures in this asset class nor have there been any unauthorised intrusions across Vector's zone substation sites. Cardax systems have proven to be robust and are performing in line with expectations.

12.9.4.4 MANAGEMENT STRATEGY

Vector's acquisition strategy will be to continue to procure security and access systems from Gallagher Cardax™ using procurement standard ESE603. Ordering is by the contractor directly with the NZ based vendor.

Asset maintenance is in accordance with Vector's maintenance standard ESM603 and is undertaken at regular planned intervals by Vector's field service providers and where required, asset-specific specialists. Planned maintenance activities include visual inspections and self-diagnostic tests which can be conducted remotely from site.

12.9.5 FIRE PROTECTION SYSTEMS

12.9.5.1 FLEET OVERVIEW

Vector's fire protection systems can be separated into two categories.

- Passive - preventative systems such as flame traps, hypoxic, smoke/heat detection, intumescent products
- Active - automated extinguishing systems such as sprinklers, Inergen gas flood, foam, fire ventilation shutters

Fire protection passive and active control is determined by risk assessment associated with the criticality of a substation's connected customers and asset value. Vector's risk evaluation procedures, guides and standards are used for risk assessment.

Vector requires zone substations either within the Auckland CBD, supplying critical customer load, or supplying downstream zone substations as a bulk point of supply, to have both passive preventative and active automated extinguishing fire protection systems. All other zone substation sites have passive preventative systems only unless otherwise determined as part of a risk-based assessment.

A local indoor fire panel installed at all zone substation sites provides collation and communication of system status and fire heat and/or smoke detection alarms to the local Cardax Security Panel for SCADA annunciation to EOC. This enables the EOC to contact FENZ to request a responder for the alarmed site in the appropriate circumstance.

CBD zone substations also signal in parallel to EOC a fire event to a FENZ approved aggregator to achieve a FENZ callout response.

12.9.5.2 POPULATION, CONDITION AND AGE

The age of individual fire protection systems is not currently recorded. It is reasonable to assume that the age of this asset class to be aligned with the age of the building it is installed in.

12.9.5.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Since the 400 V a.c. local service supply fire within Takanini zone substation in FY18 there has been a deliberate increased focus on fire protection of assets due to the safety, asset, and customer supply continuity risk that fire poses. This is now also guided by the lessons of the Penrose GXP fire within Vector's 33 kV cable trench in 2014.

Site specific hazard reviews have found the following issues or risks:

- Legacy internal doors between adjacent transformer bay fire cells are being removed where this does not impact twin emergency egress. Auto-closers will be fitted to those that provide a second egress between the fire cells.
- The replacement programme for end of technical life legacy 1970's bespoke Guardall fire protection panels will be completed in FY24. This is to achieve H&S risk minimisation: there is no failure hazard currently.
- The Penrose Hobson tunnel fire main sprinkler heads began failing in 2020. These were fully replacement by the end of FY22.
- For the eight minor cable tunnels, installation of heat/smoke detection and SCADA communication to EOC is being prioritised by the three tunnels with cable joints. Joints have already been treated with intumescent protection for fire. Investigation work in FY23 will determine the project scope.
- Due to the criticality of radio huts for network operations and distance from FENZ responders, an investigation is required to determine the need and solution for automated active fire suppression. Conclusion from investigation is expected in FY24.

The asset class population age began in the 1960's for fire protection systems in general, with replacement updates being made as existing technology has reached its end of technical or service performance life, in consultation with registered fire engineers and associated fire Standards and Codes.

12.9.5.4 MANAGEMENT STRATEGY

The fire protection asset classes have inspection and testing regimes in accordance with ESM603 which aligns with AS/NZS 4512 - Fire detection and alarm systems in buildings. Assets are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance activities. On-site assessment is by visual and thermographic inspection, and test condition, in accordance with the afore-mentioned maintenance standard.

12.9.6 EARTHING SYSTEMS

Earthing systems are required to protect people and equipment from the risk of harm of electricity due to abnormal network operation, inadvertent contact to live conductors, interaction with third party infrastructure and environmental effects such as lightning strikes. Earthing systems also ensure that protection systems operate as intended and are specifically designed to meet established performance criteria.

Every zone substation has an earth system, commonly a combination of buried earth conductors, earth rods and the building reinforcing. All asset installations with conductive equipment have their own independent earthing systems. In general, the earthing systems comprise a set or sets of pins (electrodes) driven into the earth connected using bare copper conductor. Copper is both an excellent electrical conductor and mechanically resistant to in-ground corrosion but note the risk of theft described below.

The nature of the surrounding soil and surface covering play an integral part in the performance of the earthing system. The effects of local soil resistivity and covering (e.g. metal chip and asphalt) are included in the overall analysis of earth system performance and are covered by step and touch voltage measurement.

12.9.6.1 CONDITION, EMERGING TRENDS AND RISKS

An earthing system is usually aligned with the age of the equipment or buildings it serves. As such it is difficult to establish an accurate age profile of the different components of an earthing system. The condition and health of earthing systems are essentially determined by visual inspection and testing.

Copper theft remains an ongoing issue. Both passive and active security measures are used as a preventative tool. Vector uses regular site inspections as part of planned maintenance regimes as a preventative measure. Raising awareness of the issue to FSPs also assists in ensuring that issues are identified and remediated as soon as practicality possible.

Construction works in existing zone substation sites run the risk of damage to earth grids. This risk is reduced by undertaking potholing to locate earth grids and up-front ground penetrating radar also assist to paint a picture of the layout of existing earth grids. To minimise harm to personnel and the public in an operational electricity substation site, damage to earthing must be minimised and immediately repaired. Earthing consists of typically copper conductor which is susceptible to corrosion in contaminated soils, by galvanic action with dissimilar metals and hazardous substances. ESM activities control this risk.

12.9.6.2 MANAGEMENT STRATEGY

Earthing systems for zone and distribution substations are installed in accordance with Vector engineering standards ESE704 and ESE506 respectively. Earthing design incorporates a risk-based approach for safety of nearby public and Vector's own personnel including control to safe touch and step voltage levels. Fault levels are controlled to 13.1 kA for distribution network equipment and 26.0 kA for zone substation equipment. Zone substations and distribution earthing systems are subject to a thorough testing regime that is performed every five years as detailed in Vector maintenance standard ESM607.

Vector's earthing related standards reference the EEA (NZ) Guide to Power Systems Earthing Practice and the Safety Manual – Electricity Industry (SM-EI). Independent audits completed in accordance to NZS 7901 are undertaken annually to assess public safety adjacent to the zone substation property. These audits and Vector's planned maintenance regime ensures corrective actions are undertaken to maintain the design safety performance of its earthing systems.

Vector's asset strategy for earthing systems is described in strategy report EAA600 Auxiliary Systems.

12.9.6.3 REPLACE, RENEW AND DISPOSE

Power Supply Systems

DC systems assets are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance activities. Generally, the replacement timeframe is based on risk, age, identification of any systematic issues or findings as a result of routine maintenance activities.

New DC charger installations achieve an N-2 level of security to ensure that contingency remains in the system while a charger is out of service during maintenance or testing.

Programs of work are triggered by new standards or regulatory requirements, or systemic environmental changes, asset failures or end-of-life assets. The solution is determined by reference to customer and business needs, and in conjunction with asset vendors or other industry bodies with recognised technical knowledge.

Load Management Systems

Assisting the replacement strategy is the transfer of Vector's management of streetlights to Auckland Transport as they migrate these to LED luminaries with a new radio/cellular switching control technology. Auckland Transport's programme began in 2014 and is planned for completion in 2023. The same systems we use to manage streetlights are used to manage customer hot water cylinders and must be retained until the end of FY23 when the control of Auckland Council streetlights will be fully transferred to Auckland Transport.

Capacitor Banks

There are no capacitor bank investments planned in the upcoming AMP period

Security, Access and Fire Protection Systems

The installation of seven zone substation thermal imaging detection systems is planned for in the upcoming AMP period. Section 12 Appendix with detailed programme forecast capex tables.

Earthing Systems

Assets are replaced when they reach their end of functional life, or pose a non-performance or health and safety risk, as detected during routine planned maintenance and its forecast expenditure is thus included under OPEX.

12.9.7 FORECAST SPEND

The forecast capex graph shown in Figure 12-46 provides a summary of the overall capital investment for this asset header class for the 10-year AMP forecast period.

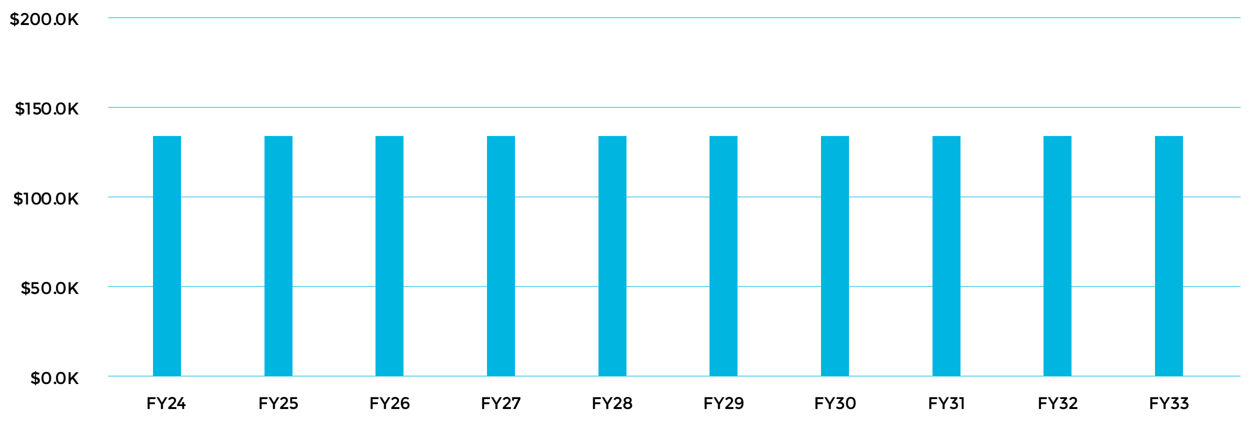


FIGURE 12.46: FORECAST CAPEX – AUXILLARY SYSTEMS

12.10 Generation and energy storage

12.10.1 UTILITY BATTERY ENERGY STORAGE SYSTEMS (BESS)

12.10.1.1 FLEET OVERVIEW

The Utility Battery Energy Storage Systems (BESS) installed in Vector's network are connected to the 22 kV and 11 kV networks. The BESS are designed to perform multiple functions applicable to the entire electricity system. The BESS installed at zone substations perform peak shaving and voltage control functions and assists with resolving the sub-transmission network security deficiencies. The BESS installed at remote ends of the 11 kV feeders improve the feeders' reliability and voltage quality. They are also able to supply electricity to customers during outages by forming microgrids.

Vector considers BESS within a suite of options when deciding on capital investment solutions to enhance the electricity network's resilience, quality of supply or network capacity expansion. BESS are installed where it is determined to be a more economical solution to address network capacity expansion in comparison to traditional primary systems investments or to defer investment in primary systems.

Most operational BESS are of the Tesla Powerpack type except for Tapora (which is a hybrid site made up of Hitachi and Samsung equipment). The Tesla Powerpacks are of modular and scalable construction that can be relocated within the network. They have also been tested and proven to comply with the safety requirements of current international standards. The BESS can be repurposed or relocated once the functions they perform at the installed location are no longer needed.

12.10.1.2 POPULATION AND AGE

We have a total of seven operational BESS, with our first 1 MW/2.3 MWh BESS at Glen Innes zone substation being in service since October 2016. Our second and third BESS were commissioned at Warkworth South and Snells Beach zone substations in 2018 and have successfully assisted in deferring network capacity expansion investment. The BESS at Kawakawa Bay and at Hobsonville Point were commissioned in February 2020 and November 2020 respectively. The BESS at Kawakawa Bay is installed at the end of a long rural feeder to improve voltage quality and feeder reliability. It also enables a segment of the feeder supplying Kawakawa Bay customers to operate as a microgrid.

The construction of the 1.14 MW / 1.254 MWh BESS at Tapora was completed in 2022. Unlike previously installed BESS on the Vector network which are Tesla Powerpack battery systems, the Tapora BESS consists of an ABB Power Conversion System and Samsung Battery System. The BESS is to improve reliability and voltage quality and support operation of a microgrid.

The BESS and a solar energy PV system installed as part of Vector Lights initiative provides renewable energy for Vector Lights on Auckland Harbour Bridge. The current BESS fleet uses Tesla Powerpack battery systems.

Key information of the BESS assets are shown in Table 12-42.

LOCATION	RATINGS	AGE
Zone Substation Glen Innes	1.0 MW / 2.3 MWh	6 years
Zone Substation Warkworth South	2.0 MW / 4.8 MWh	5 years
Zone Substation Snells Beach	2.5 MW / 6 MWh	5 years
22 kV Feeder - Vector Lights	0.25 MW/0.475 MWh	4 years
11 kV Feeder - Kawakawa Bay	1 MW / 1.7 MWh	2 years
Zone Substation Hobsonville Point	1 MW/2.0 MWh	2 years
11 kV Feeder - Tapora	1.14 MW / 1.254 MWh	1 years

TABLE 12-42: KEY INFORMATION FOR BATTERY ENERGY STORAGE SYSTEMS

12.10.1.3 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Four Tesla battery power pods failed at Warkworth South substation which was commissioned in November 2021. It took more than nine months to achieve replacement. As most of our Tesla Powerpack are first generation, the availability of spares and equipment obsolescence is of a concern.

There have been several instances of hardware and software issues affecting BESS remote control operations and indications at Tapora. Localised system resets have been required to restore communications.

12.10.1.4 CONDITION AND HEALTH

The Tesla Powerpack systems come with a 10-year warranty. Each Tesla Powerpack system is connected to the Tesla Remote Management (RM) System that enables remote monitoring, diagnostics, configuration managing and upgrading. The expected operational life of the batteries depends on aggregated energy throughput and functionality implemented. Apart from some deterioration of outdoor battery enclosures, the BESS population is in good health and condition.

12.10.1.5 MANAGEMENT STRATEGY

Electrical Energy Storage Systems are considered a vital component in transitioning to low carbon-based energy and electricity systems. They are also considered to provide essential functionality in future decentralised electricity systems, in which microgrids are to enhance the electricity system reliability and resilience.

At present, on a utility scale and for functionality required for the operation of distribution and the electricity system, lithium-ion battery-based energy storage systems are the technology of choice due to their energy density and lowest cost. We have deployed our lithium-ion BESS to understand the technology, defer investment in network capacity expansion, and improve supply quality.

Any further investment in new BESS, improving the functionality of the existing BESS will be based on a cost-benefit analysis.

12.10.1.6 DESIGN AND CONSTRUCT

Tesla Powerpack systems are technically advanced, prefabricated, modular and scalable system. The system exhibits a high level of safety features and has been tested against and demonstrated performance beyond the requirements of the international safety standards.

12.10.2 DIESEL GENERATION

12.10.2.1 FLEET OVERVIEW

Two Vector owned Diesel generating sets (genset) are currently used in Piha and a service provider owned genset is deployed at South Head. Both gensets are at the end of lengthy 11 kV feeders to improve the network reliability to these two remote communities. The generators are only operated as required during planned or unplanned network outages. The gensets are connected to the 11 kV feeders supplying the area via interconnection equipment.

Presently the diesel gensets and interfacing equipment are fixed installations on leased land with land extension agreements in place on a year-by-year basis. Vector plans to attain land in South Head to establish a permanent generation station site by FY24. The intention is to use Vector owned generating sets and step-up transformer. The same is in the pipeline for Piha but securing land in Piha is proving to be quite a challenge.

Processes are in place, to manage engagement with customers and the qualification of customers for assistance of supplying electricity from the portable diesel generators during outages. The field management of the portable generators is carried out by our field service providers.

12.10.2.2 POPULATION AND AGE

The Piha generators are owned by Vector whilst the interconnection equipment is leased. At the South Head location two 1.25 MVA diesel generators and interconnection equipment are presently leased. The Vector owned diesel gensets installed at Piha are around 3 years old and are infrequently used (i.e. used only during outages). This implies very low wear and tear and of course also low carbon emissions.

12.10.2.3 CONDITION AND HEALTH

The gensets are in good condition and are maintained as part of an agreement with a generator service provider.

12.10.2.4 EXPENDITURE FORECAST

Because of its focus on network reliability, the capex forecast for permanent generation sites at Piha and Southhead are shown in Section 11, Network Reliability.

12.10.3 RESIDENTIAL PHOTOVOLTAIC (PV) AND BATTERY ENERGY STORAGE SYSTEMS (BESS)

12.10.3.1 FLEET OVERVIEW

Initially, Sunverge and SunGenie BESS with rated energy capacity of 10.7 kWh were installed. 253 SunGenie BESS are in operation.

Subsequently, Tesla Powerwall BESS have been installed. Tesla Powerwall generation 1 has 2 kW rated power and 6.4 kWh rated energy capacity. The latest Tesla Powerwalls (generation 2) have a rated power of 5 kW and rated energy capacity 13.5 kWh,

12.10.3.2 POPULATION AND AGE

Table 12-43 below summarises our population of installed combined residential solar PV energy and battery energy storage systems, and stand-alone residential battery energy storage systems.

ASSET	QUANTITY
Solar Photovoltaic combined with Battery Energy Storage Systems	425
Residential Battery Energy Systems (no solar)	218

TABLE 12-43: KEY INFORMATION FOR SOLAR/BATTERY AND STAND-ALONE BATTERY SYSTEM INSTALLATIONS

Figure 12-47 and Figure 12-48 shows the age profiles for solar/battery installations and stand-alone battery installations, respectively.

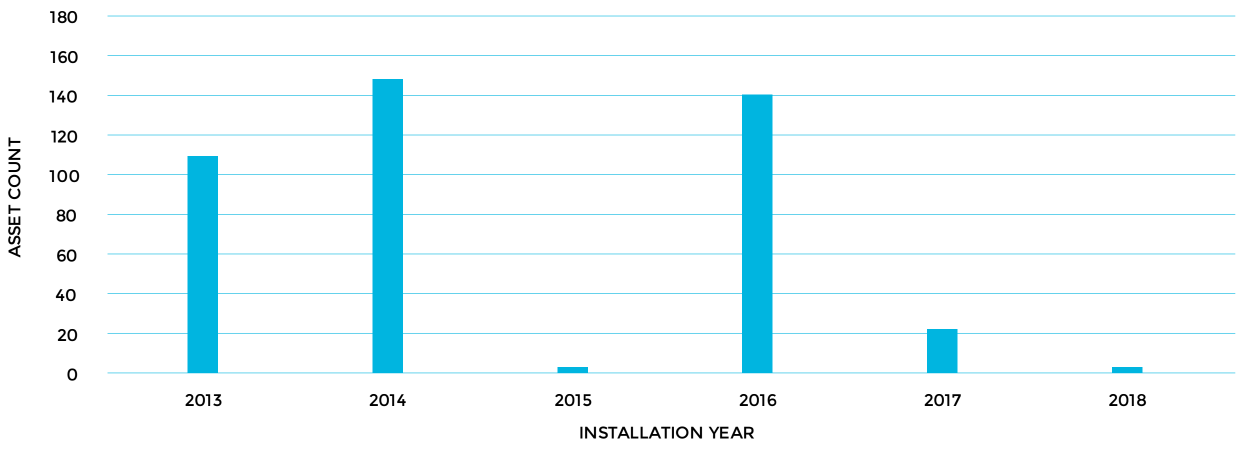


FIGURE 12.47: AGE PROFILE FOR SOLAR PV AND BATTERY ENERGY STORAGE SYSTEM INSTALLATIONS

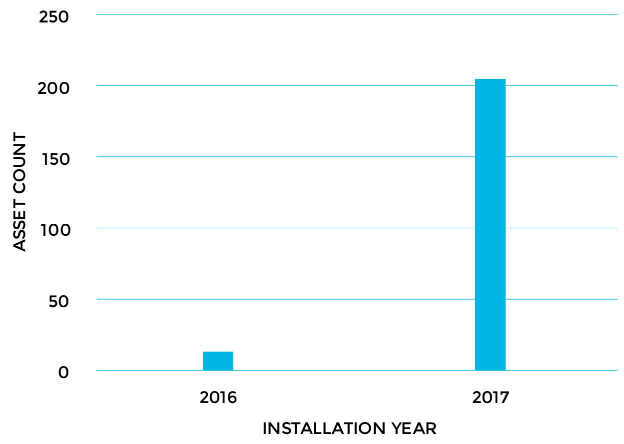


FIGURE 12.48: AGE PROFILE FOR BATTERY ENERGY STORAGE SYSTEM INSTALLATIONS

12.10.3.3 CONDITION AND HEALTH

Solar panels and battery installations form part of our maintenance regime for which provision is made in our OPEX budget. The solar panel and battery populations are relatively young, and apart from teething issues with operating software, we have not experienced systemic failures in our solar panel or battery fleets. However, we have experienced a deterioration of the steel enclosures where they exist in an outdoor environment.

12.10.4 DISTRIBUTION ELECTRICAL VEHICLE (EV) CHARGING STATIONS

12.10.4.1 FLEET OVERVIEW

With the electrification of transportation the integration of public EV charging stations into the electricity network and the potential impact on infrastructure investment needs to be carefully considered to avoid overloading and mitigate an exponential increase in peak load.

In 2016 we commenced on a programme of works to install EV charging stations in strategic public locations over the wider Auckland region as a trial. The purpose of the trial was to understand the network impacts of public EV charging so that we could plan for a future where EVs are much more common on our roads. With EV ownership increasing, growing numbers of participants in the market, maturing technology, and our understanding of network impact greatly enhanced in both public and home charging, we have met our objectives and are assessing the on-going business model for these public EV chargers.

We also have a number of EV charging stations in the basement of our main office building to charge our own fleet of EVs as well as charging stations in our office parking area for visiting customers with EVs.

Starting in 2019, Vector installed 200 controllable 7 kW EV charging stations in customer premises over the wider Auckland region including Waiheke Island. These were being trialled to understand the peak demands caused by EV chargers, the impact on peak demand by controlling chargers and the customer experience if chargers are controlled as well as gain information for EV charger customer habits and patterns in general. With our objections of understanding how EV chargers impact the network, Vector does not plan to add any EV chargers.

12.10.4.2 POPULATION AND AGE

The table below summarises our population of public EV charging stations. The first units were installed in 2016 with the latest installed in 2018.

ASSET TYPE	ASSET QUANTITY
A.C. EV Charging Stations	16
A.C Residential Smart EV Charging Stations	200
D.C. EV Fast Charging Stations	18
A.C. V2G EV Charging Stations in Vector's Office Building	2
A.C. EV Charging Stations in Vector's Office Building	12

TABLE 12-44: KEY STATISTICS FOR EV CHARGER STATIONS

12.10.4.3 CONDITION AND HEALTH

EV charging stations form part of our maintenance regime for which provision is made in our OPEX budget. The EV charging station fleet is young, and apart from some teething issues that are often experienced with a new asset class, most of the fleet is in good health.

12.10.5 FORECAST SPEND

Because of their focus on the improvement of reliability in the network, the forecast capex investment for the installation of permanent generating sites at Piha and South Head are included in Section 11, Network Reliability. Planned, corrective and any other maintenance costs related to the generation and energy storage assets are included in the OPEX forecasts in AMP 2023.

12.11 Infrastructure and facilities

Infrastructure and facilities reside across the Vector network. The purpose of these assets is to provide a means of siting and housing primary and secondary zone substation equipment, digital microwave radio systems and customer hot water load management infrastructure, for the following reasons:

1. Security and safety for the public
2. Security and safety for Vector personnel
3. Operational security plus environmental and performance safety for electricity network assets

This Section describes our Infrastructure and Facilities fleet and provides a summary of our associated asset management practices. The fleet consists of two subcategories:

1. Buildings and Grounds
2. Cable Tunnels

12.11.1 BUILDINGS AND GROUNDS

Vector's buildings and grounds portfolio includes zone substation buildings housing protection, communications, indoor switchgear, and ripple injection plant. Site grounds are secured from entry by boundary fences, and contain access driveways, potable, storm and wastewater infrastructure, security systems, and gated access ways. The degree of security is risk-based determined by customer and network asset importance, location and risk of unobserved intrusion. Vegetation and fencing management are key to site security and for personnel, public and asset safety.

12.11.1.1 FLEET OVERVIEW

Buildings are constructed of various materials including reinforced steel cast in-situ or masonry block, light timber frame, since 2008 precast tilt slab concrete, and since circa 2010 sandwich insulated panel (SIP). Unreinforced masonry brick infill panels between reinforced concrete pilasters and bond beams are typical of pre-1960's era construction, with this construction having the highest risk of seismic failure. Key statistics of the buildings and grounds assets are shown in Table 12-45.

TYPE	ASSET QUANTITY
Customer Substation Buildings	126
Substation Buildings and Grounds	119

TABLE 12-45: BUILDINGS AND GROUNDS FLEET OVERVIEW

12.11.1.2 POPULATION AND AGE

The expected life for the building fleet is 80 to 100 years with an onset of unreliability between 40 to 60 years. Figure 12-50 illustrates the age profile of Vector zone substation buildings. Their average age is 36 years.

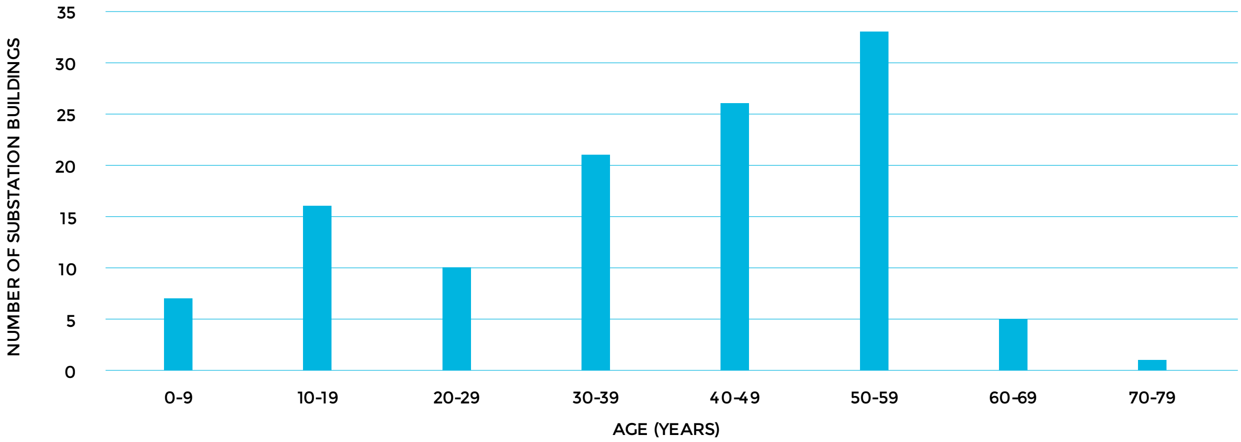


FIGURE 12.49: POPULATION AND AGE PROFIILE FOR SUBSTATION BUILDINGS

12.11.1.3 CONDITION AND HEALTH

Vector buildings and grounds fleet is ageing in accordance with expected industry trends, and we are actively monitoring their health and condition to ensure we achieve the optimum life from the fleet. We manage our buildings in perpetuity, except for where substation primary electricity asset renewal requires a rebuild for additional space than the existing building allows

12.11.1.4 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Due to our regular planned maintenance programme with corrective and planned actions our building performance is in a good state. The current drivers for our programme of work are property perimeter fencing, roofing replacements due to age and seismic performance. We have assessed the higher risk category of zone substation buildings against the New Zealand Society of Earthquake Engineering (NZSEE) grades using engineering specialists also experienced in setting the NZ IEECP and the Christchurch earthquake re-build.

Multi-storey buildings of circa 1990 to 2010 are of variable performance within the NZ building sector due to that era's building standards, for which Vector's planned maintenance inspections target evidence of issues, as for all other buildings. A recent example is Sandringham zone substation's partial rebuild that is now achieving 100% NBS performance for its 1990's building extension that had leaky building issues that appeared outside its 15-year Council code-compliance performance.

NZS7901 annual external assessor audits provide a risk-based independent assessment of zone substation property perimeter safety to the public, with their recommendations and observations corrected on site, and where required the updating of standards, and knowledge sharing with designer and planned maintenance practices. We also monitor sites with SMF with the intention that if deemed in the future to be a H&S hazard we have the necessary records to remedy.

There are substation buildings in low lying ground that are prone to flooding, which was highlighted more than ever during the Jan-Feb 2022 cyclone and, these will form part of capital projects to either harden against the impact of climate change, rebuild on higher ground or other distribution network solution as described in Section 12 Appendix.

12.11.1.5 MANAGEMENT STRATEGY

The management strategy for the buildings and grounds fleet is based on safety and asset condition but the impact of climate change and how to harden facilities against such impacts are becoming important considerations. It is informed by condition data which is being continuously improved with information gathered by our field service providers during planned maintenance inspections to ESM701. This approach aligns with our asset management objective of safety and reliability underpinned by risk-based failure mode effect analysis (FMEA).

12.11.1.6 DESIGN AND CONSTRUCT

Vector as part of its conceptual development of new substation buildings and grounds, integrates the design within the surrounding environment and in conjunction with the Auckland unitary plan. In urban and rural areas, we make our sites as unobtrusive as practicable, with aesthetics incorporating architectural and open landscape treatment sensitive to the surrounding neighbourhood. When we renew existing substation buildings, we consider changing demographics and where practicable adapt the substation appearance to align with these trends. As stated above, the impact of climate change is becoming an ever-increasing issue to consider.

Specification standards for the design and construction of new buildings and grounds are design standards ESE701, ESE702 and AS2067. Although electricity utility operator sites are not within the NZ Building Act: 2004 and our buildings are classed as unoccupied, for prudency our standards incorporate the requirements of the NZ Building Code and electrical industry Standards inclusive of AS2067.

12.11.1.7 OPERATE AND MAINTAIN

Vector routinely inspect buildings and grounds fleet by qualified personnel to ensure they remain fit for purpose. Remedial work is scheduled based on personnel and asset safety, and asset performance condition and functional importance. Vector's maintenance standard ESM701 comprehensively details the planned, corrective, and reactive maintenance requirements.

12.11.2 CABLE TUNNELS

Vector cable tunnels are installed where there is no other practical cost-effective means to install and maintain electricity cables. These satisfy the requirements of motorway crossings or mass cable runs within congested and difficult to access routes such as in the CBD.

The tunnel fleet houses extra high voltage power cables connected to Transpower grid exit point supply substations and between Vector zone substations.

This asset class includes the tunnel's structure and access security, ground water drainage pumps, active fire suppression where warranted and small power electrical circuits.

The 9.2km long Penrose-Hobson Tunnel at between 20 and 60 m underground as the land lies has added infrastructure of dual 375kW ventilation fans, five 37kW ground water pumps, a light rail system for expedient access, fire sprinkler tunnel and shaft deluge fire protection, permanent gas sensors, and a digital radio system, all with remote systems status to the Vector electricity operations centre.

All the tunnels are defined as confined spaces and are restricted to entry by personnel trained in those safety procedures.

12.11.2.1 FLEET OVERVIEW

Vector has one major (9,200m) and six minor (total length 762m) cable tunnels.

12.11.2.2 POPULATION AND AGE

The expected life for cable tunnel structures is between 80 to 100 years with an onset of unreliability between 60 and 80 years. The electrical and mechanical, secondary and process systems within the tunnels have a typical replacement lifecycle of 15 to 20 years.

12.11.2.3 CONDITION AND HEALTH

The cable tunnel fleet is ageing against industry norm expectations. We are actively monitoring and maintaining their health and condition within our Planned Maintenance regime (ESM708 and ESM709) to ensure we achieve optimum fleet life.

12.11.2.4 ASSET PERFORMANCE, EMERGING TRENDS AND RISKS

Vector completes five-yearly structural and seismic surveys using certified structural engineers of proven experience in tunnel design and construction for tunnels. The survey results continue to show good asset performance. A seismic event will result in a structural survey after the event has safely subsided to ensure asset integrity and that entry is safe for personnel.

HILP risk for all Vector cable tunnels is impaired ventilation, atmospheric gas ingress, fire, or ground water flood. Vector uses a process safety approach to assess tunnel hazards and their controls, with the electricity operation and planned maintenance standards providing the method and frequency for their performance inspection and correction.

Emerging trends and risks are for tunnel ancillary and process systems as these approach 15 to 20 years of age within high moisture environments. Our maintenance and replacement program addresses this.

12.11.2.5 MANAGEMENT STRATEGY

The management strategy for the cable tunnel fleet is based on safety and asset condition. It is informed by condition data which is being continuously improved with information gathered by our field service providers.

12.11.2.6 DESIGN AND CONSTRUCT

Tunnels are designed, certified, and constructed as a professionally engineered specific design since cable tunnels do not fall within the NZ Building Code. Vector does not have specification standards for the design and construction of new cable tunnels, and international tunnel standards would apply at the time, plus IEC and AS/NZS standards including health and safety.

12.11.2.7 OPERATE AND MAINTAIN

Vector routinely inspects its cable tunnels to ensure they remain fit for purpose. Remedial work is scheduled based on personnel and asset safety, and asset performance condition and functional importance. Vector's maintenance standard ESM701, ESM708 and EMS709 comprehensively details these planned, corrective and reactive maintenance requirements for its tunnels and their associated above ground "portal" buildings fleet.

12.11.3 REPLACE, RENEW AND DISPOSE

12.11.3.1 BUILDINGS AND GROUNDS

Buildings and grounds renewals and disposal programmes are driven by seismic upgrades, additional primary equipment (switchgear) or network growth replacements and building performance to meet its intended function. Climate change and hardening against the impact of climate change is becoming an important consideration. Buildings found to not meet the current standard for seismic compliance then become part of a seismic strengthening programme, or if it is uneconomical to do so they are replaced.

Each building and grounds site that requires asset replacement is inspected to ascertain the scope of works and site constraints. Planned maintenance findings and predicted lifecycle costs are further inputs. This information is used to build a cost-benefit risk-based NPV estimate for forecast expenditure. As part of any building replacement or program, the new facility must meet current standards, codes of practice and legislative requirements.

12.11.3.2 CABLE TUNNELS

In an unlikely event a Vector tunnel is no longer required for cable routes, provided it is structurally sound, then it will be sealed from access and left in-situ. If not structurally sound, then pressure injected concrete infill is one method to provide its required ongoing safety performance. Tunnel ancillary systems are renewed as required and the end-of-life equipment disposed of at environmentally certified facilities.

Tunnel ancillary's asset replacement ascertains the scope of work including site constraints, planned maintenance findings and predicted lifecycle costs. This information is used to build a cost-benefit risk-based NPV estimate for forecast expenditure. New equipment and systems must meet current standards, codes of practice and legislative requirements.

12.11.4 FORECAST SPEND

Detailed and individual programme forecasts for infrastructure and facilities as well as cable tunnel programmes of work are included in Section 12, Appendix. The forecast chart below is a summary of all the capex for infrastructure and facilities as well as cables. The only exception is the potential future replacement of the personnel egress ladder in the tunnel shaft at Newmarket substation. The replacement of this ladder is driven by safety, and while annual maintenance inspections show no degradation, a nominal allowance is prudently included in the forecast capex in Section 11, Network Reliability.

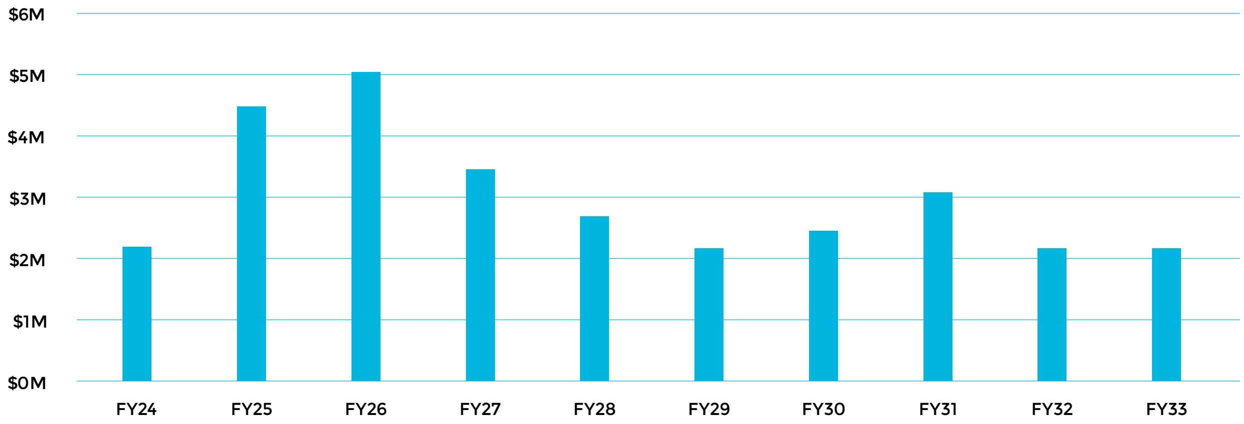


FIGURE 12.50: FORECAST CAPEX – INFRASTRUCTURE AND FACILITIES

SECTION 12A

Appendix: Asset replacement and renewal

12a – Asset replacement and renewal

12a.1 Overview

This Appendix provides details for significant asset replacement and renewal projects that have costs of $1m and over. All dollar values are nominal and include inflation. For easy reference, the programmes of work are also shown.

12a.2 Primary switchgear

12a.2.1 MANGERE EAST 11 KV VACUUM CIRCUIT BREAKERS RETROFIT

The ten 11 kV feeder CBs in Mangere East ZSS are first-generation 11 kV Reyrolle Pacific LMVP vacuum CBs. At the time when these Reyrolle vacuum CBs were installed at Mangere East ZSS (in 1986), the vacuum technology was only available for feeder CBs; the two incomer CBs and the bus coupler CBS were still Reyrolle Pacific ZMT2 oil filled CBs. Both types, the vacuum and oil CBs, are equipped with modern SEL numerical protection relays.

This switchboard underwent an arc-fault containment upgrade in 2018 with the addition of lateral arc containment shields and CB cubicle "behind-closed-door" racking systems. The new arc doors however are not type tested for oil filled CBs and the project will see the replacement of the two incomer and one bus coupler oil filled CBs with vacuum CB trucks and replacement of their CTs to new Vector standards.

The vacuum CB trucks in the existing 1986 vintage vacuum feeder CBs are first-generation vacuum CBs but replacement of these CBs is not forecast in this AMP with present condition information in hand. Further testing is required on the feeder vacuum CBs to determine whether it is technically and economically viable to replace the vacuum interrupter bottles only or a full-scale CB replacement.

All the CB rollout plates in this ZSS are in poor condition and will be replaced on all CBs. New XLPE cables will be installed from the two transformers and the transformer oil filled termination boxes will be replaced. VAMP 125 arc detection will be installed in the two incomers and bus section CB.

The existing VT powered rectifier DC substation supplies will be replaced with a Vector standard 110V DC system.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Mangere East 11 kV vacuum CB retrofit	0.56										0.56

12a.2.2 FREEMANS BAY 11 KV SWITCHBOARD REPLACEMENT

Freemans Bay supplies large residential areas in Ponsonby as well as a large portion of the commercial strip in Ponsonby Rd. It also supplies a large part of the Wynyard/tank farm and St Mary's Bay; areas that are fast developing and includes major office and hotel developments. Freemans Bay ZSS is presently fitted with Brush Electric (Hawker Siddeley) R4/2MK4 oil filled 11 kV switchgear fitted with GEC31 electro-mechanical relays.

The switchgear and relays were manufactured in 1967. There is sufficient space in the 11 kV switchroom to undertake an in-situ 11 kV replacement. The switchgear building and transformer enclosures have been assessed for seismic compliance and achieves 100% of NBS for IL3 buildings but some civil upgrades will be undertaken. The civil works will consist of the construction of a cable trench, installation of ducts and replacement of doors with Vector standard safety doors with crash bars. An HVAC system that includes a system for positive pressure will be installed and lighting will be upgraded to new Vector standard LED lighting.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Freemans Bay 11 kV SWBD replacement	1.96										1.96

12a.2.3 PAKURANGA 11 KV SWITCHBOARD REPLACEMENT

The 11 kV switchgear in Pakuranga ZSS is a 1969 vintage Brush R4/2 MK4 oil filled switchgear with electro-mechanical protection relays. The switchgear and relays are not vendor supported and the switchgear is nearing the end of life. The asset health and criticality as per our CBARM model requires the switchgear to be replaced in the AMP planning period. There is enough room in the existing 11 kV switchroom to undertake an in-situ staged replacement and allow room for two additional panels if a switchboard extension is required.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Pakuranga 11 kV SWBD replacement	2.70										2.70

12a.2.4 WIRI 11 KV SWITCHBOARD REPLACEMENT

Wiri ZSS is a three transformer ZSS: three 15/20 MVA (ONAN/ONAF) Tyree power transformers. The 11 kV switchgear in Wiri ZSS consists of seven Yorkshire SF_6 fixed pattern CBs with SEL numerical relays (installed 1998), two 2011 installed Reyrolle LMVP vacuum CBs and 14 Reyrolle England LMT2 CBs with electro-mechanical relays installed in 1983. The suite is configured as a three-bus section switch with two bus-couplers: transformers T2 and T3 supply the Reyrolle England switchgear portion.

This new Wiri 11 kV switchboard will contain vacuum interrupting CBs equipped with numerical protection relays. The existing cable terminations will not be re-used, instead the existing PILC cables entering the substation replaced with XLPE tails fitted with new terminations. The cable boxes will be fitted with arc detection sensors along with VAMP 125 arc detection relays. The transformer management systems will also be replaced under this project and a new Vector standard 110 V DC system will be installed.

The switchroom building achieves 80% (IL3) of NBS and civil works will be minor upgrades e.g. installation of doors with crash bars.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Wiri 11 kV SWBD replacement	5.99										5.99

12a.2.5 HORSESHOE BUSH 33 KV SWITCHING STATION REPLACEMENT

Horseshoe Bush is a 33 kV switching station that connects eleven x 1.1 MVA generators at the Redvale landfill to the Vector subtransmission network via a 33 kV fault interrupter (not a CB). Two 33 kV subtransmision circuits, from Helensville ZSS and Coatesville respectively, are connected to Horseshoe Bush via 33 kV disconnectors. An overhead subtransmission line links to the subtransmission circuit between Silverdale ZSS and Spur Rd, via a disconnector at Horseshoe Bush.

Vector only has a few of the US manufactured S&C switches in service and the protection relays are first-generation numerical units that are orphans in Vector's relay population. The switch housing has simply not performed to expectations in the outdoor environment with rapid rusting and other metal fatigue issues that require undue maintenance. Any refurbishment of the existing enclosures will most likely require shipping to the manufacturer in Chicago. This switch, although in a rural network, will increase in importance because of the rapid expansion and development forecast under the Unitary Plan in the area north of Auckland.

The existing switchgear will be replaced in its entirety (including protection, SCADA/Communications, DC supplies) with a five-panel Schneider GHA 36kV 1,250 amp rated indoor switchboard fitted with Siemens Siprotec protection devices. The site has ample space for the installation of a concrete tilt slab switchroom building to house the new switchboard and auxiliary equipment.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Horseshoe Bush 33 kV switch replacement	1.26										1.26

12a.2.6 HOBSONVILLE 11 KV SWITCHBOARD REPLACEMENT

The 11 kV switchgear in Hobsonville ZSS is of the South Wales C4X oil filled type installed in 1975 and is fitted with electro-mechanical relays. A staged in-situ 11 kV switchgear replacement is not practical because of the limited space in the switchroom and a new switchroom will be installed. This switchroom will be designed and constructed with sufficient room for a future 33 kV replacement of the outdoor switchgear with indoor switchgear.

The new 11 kV switchboard will make provision for future additional 11 kV feeders and include all ancillary works and balance of plant e.g. DC system, SCADA panel, control and instrumentation.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Hobsonville 11 kV SWBD replacement		0.82	5.80								6.62

12a.2.7 NEW LYNN 11 KV SWITCHBOARD REPLACEMENT

The New Lynn 11 kV switchboard consists of a mixture of South Wales D4XD 1954 vintage switchgear, three C8X 1954 vintage CBs and three South Wales HG12 SF_6 CBs installed in 1987. All protection relays are electro-mechanical. Based on asset health and criticality the oil filled CBs need to be replaced but the complete suite including the three later model South Wales SF_6 CBs will also be replaced because a partial replacement will be physically challenging and costly to achieve. The three recovered SF_6 CBs will be retained as a source of spares.

The existing 11 kV switchroom does not have any space for a staged 11 kV switchboard replacement regardless that the building achieves 90% seismic compliance of NBS. There is sufficient space in Vector's designated substation land to construct a new switchgear building. It will be designed and constructed to house new indoor 33 kV switchgear that will be undertaken after the 11 kV replacement. The site is within a flood plain and the substation building design will consider this. The works will include the required balance of plant installation, e.g. 110 V Vector standard DC panel, SCADA panel and communications panel.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
New Lynn 11 kV SWBD replacement		0.60	5.68								6.28

12a.2.8 ROSEBANK 11 KV SWITCHBOARD REPLACEMENT

Rosebank ZSS supplies the whole of the Rosebank peninsula and parts of Waterview that includes a large base of small and medium enterprises and industrial/commercial customers as well as 4,345 residential customers. The 11 kV switchgear consists of twelve Reyrolle UK LMT oil-filled CBs with electro-mechanical protection relays installed in 1970 and four Reyrolle LMVP vacuum CBs with Siemens numerical protection relays installed in 2007. The oil filled switchgear and the protection relays are not vendor supported and the substation has a history of faults on VTs and CTs. The output from the switchgear CBARM model categorises this switchboard as having a R4 rating (maximum risk).

Theoretically, this 1970s Reyrolle switchgear could be retrofitted with vacuum CB trucks but the general condition of the switchgear, cable termination boxes and secondary cabinets is such that the cost of retrofitting versus the benefit and asset life extension is not worthwhile. It will be more beneficial from a safety, operational and asset life point of view to replace the entire switchboard. The new switchgear will be fitted with Vector standard numerical protection relays and the 1970s vintage Reyrolle switchgear suite will be scrapped but selected parts will be retained as strategic spares for similar switches in service. The existing Long and Crawford 11 kV local supply substation RMU will be replaced.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Rosebank 11 kV SWBD replacement			4.95								4.95

12a.2.9 SABULITE 33 KV OUTDOOR TO INDOOR SWITCHBOARD CONVERSION

Sabulite ZSS is the distribution node for Kelston, Glendene South and North, Glen Eden East and New Lynn West in the Auckland Waitekere region and supplies 8,271 residential customers, 740 small and medium enterprises and 44 industrial customers. In 2012 the then existing South Wales 11 kV type C4/C8 X series of switchgear was replaced with a Schneider GHA fixed pattern switchboard in a Portacom style building that was designed with sufficient space for a 33 kV switchboard to be installed. The 33 kV outdoor CBs at Sabulite consist of five Nissin KOR type oil filled CBs installed in 1966 and one GEC VOX SF_6 outdoor live tank type CB installed in 2008. The protection relays for the 33 kV CBs were upgraded in 2008 to Siemens numerical devices.

The Nissin KOR oil filled CBs have been identified as presenting a network risk because if and when they fail, they tend to do so spectacularly with a risk of collateral damage. The 33 kV outdoor switchgear will be replaced with indoor fixed pattern switchgear in the AMP 2023 planning period. The works will include cutting, joining and turning new XLPE 33 kV tails to the indoor switchgear and civil and structural works under the existing Portacom to make appropriate space for the 33 kV cable tails. Replacement of the numerical relays will be required at the remote end 33 kV zone substations connected to Sabulite.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Sabulite 33 kV SWBD ODID			4.03								4.03

12a.2.10 ROCKFIELD 11 KV SWITCHBOARD REPLACEMENT

The 11 kV switchgear at Rockfield ZSS is a combination of 1978 vintage Reyrolle UK LMT oil-filled CBs with CDG electro-mechanical relays, and two RPS LMVP vacuum CBSs installed in 1998 and 2005 respectively. Although the Reyrolle oil-filled CB's can be retrofitted with modern vacuum CB's, pressure from expected demand growth on Rockfield ZSS along with the benefits of having the switchboard of the same vintage has prompted a complete switchboard replacement. The scope will include the installation of modern numerical protection relays, replacement of the transformer management system, and the existing VT supplied rectifier units will be replaced with a Vector standard 110 V DC system.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Rockfield 11 kV SWBD replacement			0.44	2.70							3.14

12a.2.11 NEW LYNN 33 KV OUTDOOR TO INDOOR SWITCHBOARD CONVERSION

The 33 kV outdoor switchgear in New Lynn ZSS consists of a variety of Siemens India oil filled CBs installed in the mid-eighties and a Vox SF_6 CB installed in 2007. The asset health and criticality of the 33 kV outdoor switchgear is such that it will be retained in service until after the 11 kV switchgear has been replaced. Accommodation for the 33 kV switchgear will be designed and constructed as part of the 11 kV switchgear project.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
New Lynn 33 kV SWBD ODID			0.59	4.55							5.13

12a.2.12 WAIKAUKAU 33 KV SWITCHBOARD OUTDOOR TO INDOOR CONVERSION

The 33 kV substation at Waikaukau ZSS consists of an extensive outdoor switchyard on a combination of concrete and timber support structures with 70s vintage porcelain insulators and rocking type disconnectors/air break switches. There are ten outdoor 33 kV CBs and eight bus disconnectors in the overhead bus structure but no remote controlled bus coupler CB: any bus fault means a manual operation of bus disconnectors on site with prolonged outage time.

The 33 kV CBs are a mix of Nissin KOR-22 and Takaoka 3ORO oil filled types that have been identified as a risk to operating personnel because the failure of these type of CBs has resulted in explosions and collateral damage. A 1986 installed Inoue outdoor oil CB exists and an Areva VOX SF_6 outdoor CB replaced an oil filled CB in 2008. Protection relays are a mix of Siemens and SEL previous generation numerical relays in indoor protection panels in the relay building on site.

This ZSS is in a floodplain and at risk during heavy downpours. In March 2017 and again in January 2023 the substation was shut down due to flooding and had to be backfed while a clean-up operation was undertaken.

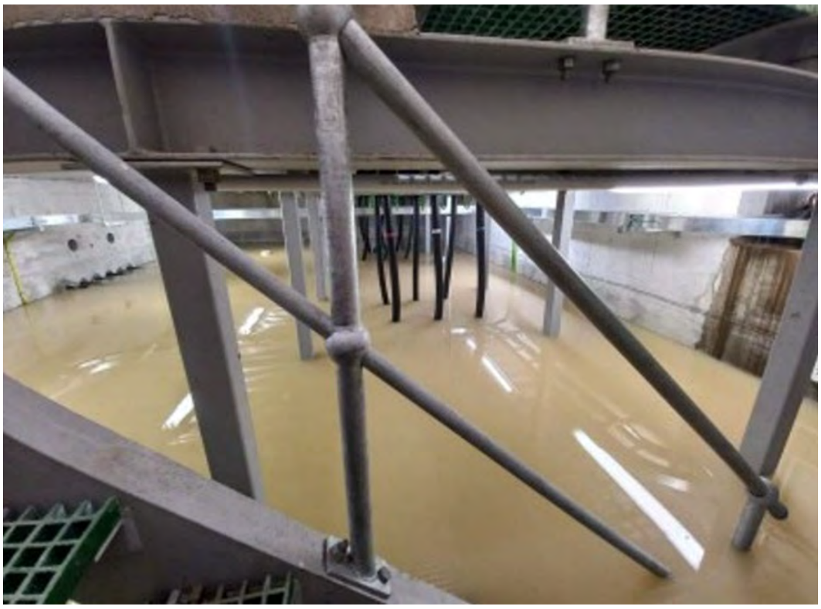


FIGURE 12A-1: WAIKAUKAU ZSS BUILDING BASEMENT DURING FLOOD JANUARY 2023

The extensive size of the outdoor switchyard also makes it prone to outages by bird and vermin. A failure mode of cracking of insulators in the rocking disconnectors have been observed and resulted in a total outage of the 33 kV switchyard in January 2019. Apart from the inconvenience to customers this also resulted in undue SAIDI.

The 33 kV outdoor switchyard and CBs will be replaced with modern fixed pattern switchgear. For this purpose, a combined 33 kV/11 kV switchroom building will be constructed towards the front of the property that sits at a higher elevation (the 11 kV switchgear replacement will be undertaken separately in a subsequent year and is described further below). The switchroom will be designed with a floor height that takes into consideration the Unitary Plan flood plain modelling to prevent water from reaching the substation floor level.

Many 33 kV overhead lines enter the substation and as part of the works, this will be tidied up and replaced with underground cable portions into the new switchgear from cable risers. The transformers will also be relocated under the project to purpose built enclosures at a location on site with a higher elevation.

By the time this project will be delivered the existing numerical protection relays would have reached the end of life and the new fixed pattern switchgear will be delivered with generation 5 numerical relays and relays at the remote ZSS ends supplied from Waikaukau will also be replaced with generation 5 relays.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Waikaukau 33 kV SWBD ODID				0.80	10.12						10.92

12a.2.13 WAIKAUKAU 11 KV SWITCHBOARD REPLACEMENT

The 11 kV switchboard in Waikaukau ZSS is a 1975 vintage South Wales suite that consists of five oil filled CBs: a mixture of D8 and C4X1 types fitted with CDG electro-mechanical protection relays. The South Wales oil filled switchgear is not supported by vendors and has been identified in Vector's asset strategy for replacement. The 11 kV switchboard will be replaced with fixed pattern low maintenance switchgear and numerical protection relays in a switchgear room installed in a prior year as part of the 33 kV outdoor switchyard replacement. The switchgear room height will consider the flood plain height as experienced in the Jan-Feb 2023 cyclone to mitigate the risk of flooding and harden this zone substation for the impact of climate change.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Waikaukau 11 kV SWBD replacement				0.40	3.07						3.47

12a.2.14 HENDERSON VALLEY 11 KV SWITCHBOARD REPLACEMENT

The Henderson Valley 11 kV switchboard consists of 15 Reyrolle oil filled CBs: a mix of 1968 vintage LMT type 23T CBs and LMT X6 CBs. The existing protection relays are Reyrolle type TJV electro-mechanical overcurrent and earth fault relays with no relay supervision, no fault recording or fault location analysis capability and no capability for remote access to check and change protection settings or to access data in the relays. They also do not have the ability for definite time settings. Bay control on this old suite of CBs is via RTUs. The asset health and criticality of this switchgear is such that it is scheduled for replacement before the conversion of the 33 kV outdoor switchgear at Henderson Valley. The accommodation for the new fixed pattern 11 kV switchgear will be designed and constructed to make provision for the 33 kV outdoor to indoor conversion works described separately and that will follow the completion of this project. This zone substation is in a low-lying area and its design will consider flood levels taking cognizance of the Jan-Feb 2023 cyclone and its impacts.

The implementation of protection relays with definite time settings will allow much improved coordination with the large number of downstream reclosers and sectionalisers on the extensive Piha rural network.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Henderson Valley 11 kV SWBD replacement				0.57	4.62						5.19

12a.2.15 HILLCREST 11 KV SWITCHBOARD REPLACEMENT

Hillcrest ZSS has a 13-panel 11 kV switchboard supplied from two 12/24 MVA transformers. Two of the CBs are Reyrolle Pacific LMVP vacuum CBs installed in 2008. The remaining 11 CBs are Reyrolle Pacific LMT2 and ZMT2 oil filled CBs installed in 1990. The first-generation numerical protection relays (GEC MCGG Micom) which are known to have reliability issues will be replaced along with the transformer management system. Along with replacing unreliable and aging assets, the capacity rating of the new Hillcrest ZSS switchboard will also allow for demand growth in the Hillcrest suburb and outskirts of the Takapuna metropolitan area.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Hillcrest 11 kV SWBD replacement					4.95						4.95

12a.2.16 TAKANINI 11 KV SWITCHBOARD REPLACEMENT

The Reyrolle 11 kV switchboard at Takanini ZSS is a combination of six LMT/LMT2 oil CB's, two LMV vacuum CB's and three LMVP vacuum CB's. The switchgear vintages span across five decades with the oldest and newest being 1976 and 2014 respectively. The protection relays installed also vary and include CDG31 electro-mechanical relays, SEL-751 numerical relays and a GEC MCGG Micom first generation numerical relay. The new switchboard will contain modern numerical protection relays and vacuum interrupter CBs with capacity to complement the network reinforcement projects taking place during this AMP period.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Takanini 11 kV SWBD replacement					4.95						4.95

12a.2.17 KINGSLAND 11 KV SWITCHBOARD REPLACEMENT

Kingsland ZSS is one of the larger distribution centres in Auckland's network and it is supplied from Mt Roskill GXP onto two 110 kV/22 kV transformers that supply a 22 kV switchboard. A large (20 panel) 11 kV switchboard is supplied from the 22 kV switchboard via two 22 kV/11 kV transformers. The 11 kV switchboard is a Reyrolle Pacific switchboard installed in 1990. Although the feeder CBs all have vacuum interrupters, the three incomer CBs and two bus coupler CBs are oil filled Reyrolle Pacific LMT2 CBs. The scope of this project was originally to retrofit the oil CBs with vacuum interrupter CBs, however this was reconsidered in favour of a complete replacement in order to standardise and modernise every component of the switchboard.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Kingsland 11 kV SWBD replacement					4.95						4.95

12a.2.18 LICHFIELD 110 KV OUTDOOR CB REPLACE

The two 110 kV CBs at Lichfield ZSS are AEG type S1-145 F1 outdoor single pole encapsulated live tank SF_6 CBs commissioned in the mid-1990s. These CBs have had systemic issues with leaking SF_6 but diligent maintenance and refurbishment have kept them running. ABB still provides some technical support and spare part inventory for this type, but these CBs need to be replaced in this AMP period.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Lichfield 110 kV OD CBs replacement					0.58						0.58

12a.2.19 ST HELIERS 11 KV SWITCHBOARD REPLACEMENT

St Heliers ZSS is equipped with thirteen Reyrolle England 1970s vintage CBs that is a mixture of LMT 36T and LMT X8 types; electro-mechanical protection relays are fitted. According to the CBARM model, the risk category of this switchboard is expected to regress into the R4 category towards the end of the AMP period.

Lighting will be replaced with Vector standard LED lights and emergency lighting, and to reduce solar heat gain the windows will have a covering applied. The 1974 vintage Long and Crawford oil filled RMU in the local supply substation will be replaced with a modern equivalent under the works. The fire protection system will also be upgraded.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
St Heliers 11 kV SWBD replacement					0.32	3.74					4.06

12a.2.20 TE PAPAPA 11 KV SWITCHBOARD REPLACEMENT

Te Papapa ZSS is supplied from Penrose GXP to two 15 MVA transformers that feed a 13-panel Reyrolle England 11 kV switchboard with oil filled CBs installed in 1975. The line differential protection relays on the two 11 kV incomer CBs were modernized in 2020 to numerical protection relays that operate on a fibre optic signalling cable due to an ageing and failing copper pilot cable.

The oil filled switchgear and electro-mechanical relays are not vendor supported and will be replaced in line with Vector's asset strategy for primary switchgear. The existing substation building has structural issues and although there is space in the 11 kV switchroom for a staged in situ replacement, a new building is the preferred option to house new fixed pattern low maintenance replacement switchgear. The two numerical relays in the existing incomers will be retained as strategic spares at the time of the works. The forecast cost below is based on a new switchgear room constructed on site.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Te Papapa 11 kV SWBD replacement					0.59	5.90					6.49

12a.2.21 QUAY ST 11 KV SWITCHBOARD REPLACEMENT

Quay St ZSS is the bulk supply zone substation that supplies the lower eastern Auckland CBD including Ports of Auckland via a 22 kV and 11 kV network. It also supplies Parnell ZSS via two 22 kV subtransmission underground cables. The 22 kV ABB Calor Emag SF_6 1991 vintage installed double bus switchgear at Quay St recently (FY20/21) underwent a mid-life refurbishment which added ~20 to 30 years to its asset life. No capital works are required on this switchgear in the AMP planning period.

The 11 kV switchgear in Quay St ZSS is a double bus switchgear suite that consists of:

- 9 x Reyrolle 2LMT/MO oil filled CBs with CDG electro-mechanical protection relays installed in 1972. The switchgear has a short circuit rating of 350 MVA for 3 s;
- 17 x Yorkshire YS/L 13.8 kV rated SF_6 CBs with Siemens numerical protection relays installed in 1993. The switchgear has a short circuit rating of 476 MVA for 3 s.

The lack of vendor support, asset age, no fault analysing or data storage capability in the protection relays and high criticality of Quay St ZSS drives a replacement of the Reyrolle 2LMT oil filled CBs later in the AMP 2023 planning period. An in-situ replacement in place of the existing switchgear is simply not practical but the substation has real estate in which to install the new switchgear and undertake a staged transfer of 11 kV circuits. The Yorkshire SF_6 switchgear is still in good condition and although out of production, Vector has a repository of spares for this type to enable its retainment beyond the AMP 2023 planning period. However, the existing Siemens Siprotec 3 generation protection relays in the Yorkshire switchgear will need replacement later in the present planning period with Siprotec 5 generation numerical relays.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Quay St 11 kV SWBD replacement						0.23	4.10				4.33

12a.2.22 SUNSET RD 11 KV SWITCHBOARD REPLACEMENT

Sunset Rd ZSS in the North Shore supplies the Sunnynook area, parts of Unsworth Heights, northern parts of Wairau Valley and the extensive Constellation Rd and Upper Harbour commercial areas. It includes the North Shore police headquarters in the supply area. The 11 kV switchgear consists of 11 GEC BVP17 oil filled CBs installed in 1972. The protection relays are GEC CDG36 electro-mechanical relays of the same vintage as the switchgear. An in-situ replacement in the existing 11 kV switchroom is unlikely due to limited space and a new switchroom will likely be utilized for fixed pattern low maintenance switchgear.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Sunset Rd 11 kV SWBD replacement						1.39	4.63				6.02

12a.2.23 HENDERSON VALLEY 33 KV OUTDOOR TO INDOOR SWITCHBOARD CONVERSION

The 33 kV CBs at Henderson Valley ZSS are Takaoka type 30K0 oil filled outdoor CBs, some manufactured in 1967 and others in 1970. They exist in an outdoor switchyard with reinforced concrete bus structure supports with Canterbury type rocking disconnectors connecting to aluminium busbars. The cable support structures are steel. These outdoor oil circuit breakers are forecast to reach the end of life in this AMP period, does not have vendor support and have a known safety risk that when an internal fault occurs, it could result in the explosive expulsion of porcelain parts.

The 33 kV ODID project will follow after the construction of a new switchroom building for the 11 kV switchgear replacement project, described separately in this section. The existing 33 kV cables will be extended to new fixed pattern indoor 33 kV switchgear. The balance of plant equipment such as a DC system and SCADA panel will be replaced with modern Vector standard equipment. This 33 kV switchgear replacement is scheduled for planning and procurement to commence in FY29 and project delivery in FY30.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Henderson Valley 33 kV SWBD ODID						1.56	5.41				6.96

12a.2.24 SUNSET RD 33 KV OUTDOOR TO INDOOR CONVERSION

The 33 kV switchgear at Sunset Rd ZSS consists of seven outdoor CBs: five Takaoka 3OKO oil filled CBs, one Inoue 3OTEO oil filled CB all installed between 1978 and 1980 and one Siemens India vacuum outdoor CB installed in 2005. The oil filled CBs are of a type that has been identified as a risk and will be replaced. Numerical relays were installed on the incoming 33 kV feeder CBs in 2019 and will be returned to stock as strategic spares at the time of the replacement because the new fixed pattern switchgear will come fitted with new protection relays. The existing 11 kV switchroom (see above) will most likely be repurposed for the new 33 kV switchgear.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Sunset Rd 33 kV ODID							2.32				2.32

12a.2.25 SANDRINGHAM 11 KV SWITCHBOARD REPLACEMENT

Sandringham ZSS is fitted with a mixture of Brush Q16/2 and Brush R4/2 oil filled CBs installed in 1967; twelve CBs in total. The switchgear is fitted with electro-mechanical protection relays. Neither the switchgear nor protection relays are vendor supported and the switchgear is of the type that has been identified in Vector's asset strategy for primary switchgear, as a type to be replaced. Its ranking in the switchgear condition-based risk model calls it out for replacement in the current AMP planning period.

The existing switchroom building is a remnant of the leaky building period but extensive capital has been invested in recent years, including guttering, roofing and concrete paving to control soil erosion and seasonal swelling/shrinking around the building. The existing substation land is constrained and there is insufficient space to undertake an in-situ replacement inside the existing 11 kV switchroom and the existing building will most likely have to be extended to create space for a new 11 kV switchboard. This will require extensive geotech investigations to ensure the mass of any building additions does not impact the stability of existing buildings on site. Furthermore, the existing building foundations may require seismic upgrade and the building addition will likely have some separation so the buildings will have separate mass responses: details to be confirmed at the time of design.

The allowance in the AMP forecast estimate for this switchgear replacement is thus provisional and not firm until the afore-mentioned detailed investigations have been undertaken. This will happen closer to the time but ahead of works delivery. As part of this project, the existing PILC 11 kV incomer cables will be replaced. It is also planned to replace the existing Long and Crawford and LV distribution panel in the local supply substation at this ZSS. If necessary, Vector will deploy its mobile trailer (container) mounted 11 kV switchboard to facilitate the new switchgear installation.

The peak demand in Sandringham in the 2022 winter was 19.6 MVA and is forecasted to reach 37.0 MVA by the end of the AMP planning period. The new design and switchgear installation will make provision for easy extension of an additional 11 kV CB on either side of the bus in the future: a requirement for a new 11 kV feeder is a high likelihood.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Sandringham 11 kV SWBD replacement							0.63	5.63			6.26

12a.2.26 WOODFORD 11 KV SWITCHBOARD REPLACEMENT

Woodford ZSS is a single transformer substation that supplies a mixture of residential and commercial load. The 11 kV switchboard is presently fitted with mid-1970's Reyrolle UK oil filled 11 kV switchgear along with English Electric CDG36 electro-mechanical relays of the same vintage. There is sufficient space in the 11 kV switchroom to undertake an in-situ 11 kV replacement and no remedial work on the switchroom building is required to make this building comply with the Seismic Provisions of the Building Act.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Woodford 11 kV SWBD replacement							0.81	2.32			3.13

12a.2.27 MANLY 11 KV SWITCHBOARD REPLACEMENT

Manly ZSS supplies suburbs located on the Whangaparoa peninsula including Whangaparoa, Manly and Stanmore Bay. Vector's substation switchgear CBARM model has identified the Manly 11 kV switchboard as becoming high risk towards the end of the current AMP period and requiring replacement. The 11 kV switchgear consists of 11 GEC BVP17 oil filled CBs installed in 1972 with English Electric CDG36 electro-mechanical relays. The new switchboard will be fitted with modern numerical relays and auxiliary systems will be replaced to meet the current Vector standard.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Manly 11 kV SWBD replacement								4.86			4.86

12a.2.28 MCLEOD 11 KV SWITCHBOARD REPLACMENT

The 11 kV switchgear in McLeod ZSS is of the South Wales C4X oil filled type installed in 1975 and is fitted with electro-mechanical relays. Neither the switchgear nor protection relays have any vendor support and the equipment is nearing the end of life. A review into integrity of the switchroom building will be required to determine if a replacement is required or if it is economical to maintain for the lifetime of the new switchboard. Fixed pattern switchgear will be installed in the existing switchroom if practicable, otherwise a new switchroom will be constructed.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
McLeod 11 kV SWBD replacement								2.23			2.23

12a.2.29 EAST COAST RD 11 KV SWITCHBOARD REPLACEMENT

East Coast ZSS has a nine panel 11 kV switchboard supplied from a single 12/24 MVA transformer. Three of the CBs are Reyrolle Pacific LMVP vacuum CBs installed in 2006. The remaining six CBs are Reyrolle Pacific LMT2 oil filled CBs installed in 1989. The oil CBs are fitted with first-generation numerical protection relays (GEC MCGG Micom) while the vacuum CB's are fitted with later generation Siemens numerical relay.

Vectors substation switchgear CBARM has identified the East Coast 11 kV switchboard oil CB's as being highly critical assets with their health deteriorating towards the end of the AMP period. The switchboard will be replaced and modern numerical protection relays will be installed with the new switchboard.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
East Coast Rd 11 kV SWBD replacement								1.62			1.62

12a.2.30 NEWTON 11 KV SWITCHBOARD REPLACEMENT

Newton ZSS supplies the large commercial area in Newton, Eden Terrace and a part of Mt Eden. The 11 kV switchboard is a double bus GEC NZ type BTVP suite with oil filled CBs and GEC CDG electro-mechanical protection relays installed in 1980. The risk category of this switchboard according to the CBARM model is expected to regress into the high-risk category towards the end of the AMP period

There is no space in the switchroom for an in-situ staged replacement and insufficient space to build a new switchroom. To replace the switchboard will most likely require a major construction project to build a second level over and above the existing switchroom for new fixed pattern switchgear. This zone substation is close to a cliff in which small landslips occurred during the Jan-Feb 2023 cyclone and this will be considered in the design of this upgrade.

The investment forecast is provisional as this project requires extensive planning and investigations to select a viable option.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Newton 11 kV SWBD replacement								2.23	6.68		8.90

12a.2.31 SWITCHBOARD REPLACEMENTS IN THE LATTER PART OF THE AMP PERIOD

The forecast below is for switchboard replacements in the latter part of the AMP period that have been assessed based on asset health and criticality. Depending on the performance of the equipment as well as load growth, the priorities for these replacements might change. There is substantial and rapid industrial growth in the Hobsonville and surrounding areas. So, this ZSS is a likely candidate amongst this group for bringing forward as we move into the future.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
James St 11 kV SBWD replace									5.00		5.00
Hobsonville 33 kV SWBD ODID									2.55		2.55
Mt Albert 11 kV SWBD replace									1.78		1.60

12a.3 Zone substation power transformers

12a.3.1 MT ALBERT ZSS REPLACE TRANSFORMER T1

Mt Albert is a single transformer ZSS supplied from Mt Roskill GXP via a 3-core 195mm² (0.3 inch) PILC SWA 22 kV cable for the largest part of the route with a 500m section of 300mm² Al 1-core XLPE cable under the 2013 south-western motorway development. The single Bonar Long 12 MVA 22/11 kV transformer was installed in 1964. The replacement of this transformer was delayed in the planning period of the previous AMP because of enough backstopping to the 11 kV bus and a low forecast rate of load growth at the time. However large tracts of land have been earmarked in the area supplied by Mt Albert ZSS for large-scale urban intensification that will include high density multi-storey apartment buildings on ex Unitec land.

The peak demand in 2023 was 7.4 MVA and is forecast to reach 14.6 MVA in 2033 (almost double the demand in a decade). From a load forecast versus transformer capacity point of view the capacity is sufficient for the 10-year planning period but from 2033 and onwards the load forecast rate of growth increases and the substation security limit will be breached by 2030.

The replacement transformer size will be based on the long- term load forecast load growth and a 20 MVA transformer has been selected. For the 10-year AMP period, the existing 11 kV backstopping will suffice to provide N-1 security but the location of the transformer enclosure on the substation designated site and its layout design will allow for easy construction and installation of a 2nd transformer when this is required in the long term.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Mt Albert 33/11 kV TX Replace T1	0.92										0.92

12a.3.2 TRIANGLE RD ZSS REPLACE TRANSFORMERS T1 AND T2

Triangle Rd ZSS is a two transformer ZSS supplied from Henderson GXP via two trefoil (3 x 1-core) Aluminium 300mm² XLPE cables directly to two transformers. Transformer T1 is an ASEA 10 MVA continuous rating ON transformer manufactured in 1956 and installed in 1961 and transformer T2 is a Wilson Electric 10 MVA continuous rating ON transformer installed in 1961: both units are outdoor transformers installed in bunds complete with SEPA unit. The Triangle Rd ZSS peak demand in winter 2022 was 14.2 MVA and is forecasted reach 19.1 MVA by 2033.

These transformers were originally scheduled for replacement later in the AMP period but tests have shown that their asset health is degrading and their replacement was brought forward. Vector standard 15/20 MVA ONAN/ONAF power transformers will be installed in the same locations as the existing transformers.

A further driver for their replacement is the development of a large datacentre that will be supplied from this zone substation.

The civil works will include modification of the bunds to ensure they are suitable for the larger oil volume transformers; it will also include the construction of a firewall between the transformers and a firewall between the transformers and the existing switchgear building. The cable works will likely include new 11 kV incomer cables from the transformer terminals to new Vector standards: this will be determined under detail design.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Triangle Rd 33/11 kV TX Replace T1 & T2	3.99										3.99

12a.3.3 SOUTH HOWICK ZSS REPLACE TRANSFORMER T1

When transformer T1 South Howick failed in March 2020 it was replaced with a 15 MVA on-board radiator transformer which is not an optimal physical fit into the enclosure or for the electrical peak demand. This spare transformer was used because it was available at the time during the contingency. The winter peak demand in 2022 was 24 MVA but with energy efficiency gains under the Symphony model, solar and battery uptake is forecast to reach 28.1 MVA by 2033. T1 will be replaced with an off-tank radiator 20/30 MVA – 2-hour transformer to match off tank radiator transformer T2.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
South Howick 33/11 kV TX Replace T1	1.52										1.52

12a.3.4 HELENSVILLE ZSS REPLACE TRANSFORMERS T1 AND T2

Helensville ZSS is a 33/11 kV 7.5 MVA two transformer site fed from Transpower's Silverdale GXP via Kaukapakapa ZSS, with a backup supply from Albany GXP via Coatesville ZSS and Horseshoe bush switching station (the latter normally open operationally to break the supply ring). Both transformers are over 40 years old and have undergone midlife refurbishments, but recent asset condition tests have determined that they require replacement with T1 having the highest priority.

Two Elsewedy 15/20 MVA ONAF transformers with on tank radiators are being procured for this project. Each transformer will arrive on site with REG-DA transformer management systems fitted. The existing 11k V and 33 kV rated switchgear are all under 16 years of age and have ample remaining life. The transformers removed from site will be scrapped with any high wear components kept as critical spares if deemed to be in good condition.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Helensville 33/11 kV TX Replace T1 & T2	0.32										0.32

12a.3.5 WAIMAUKU ZSS REPLACE TRANSFORMER T1

Waimauku zone substation is a dual transformer site located in the Waimauku township and supplies power to horticultural and agricultural customers plus a growing number of residential customers. T2 is a Pauwels 10 MVA ONAN transformer that was commissioned in 2009 and is housed in a purpose-built template tilt slab constructed transformer bay. T1 is a Wilsons 7.5MVA ONAN transformer from 1961 and it is in an aged condition. With the substation peak demand exceeding the thermal rating of transformer T2, a failure of T1 poses a significant supply security risk to the Waimauku township and the surrounding area.

Transformer T1 will be replaced with a Vector standard 15/20MVA ONAN/ONAF transformer. There is sufficient space to install the new transformer in a similar location as the existing, however the outdoor breaker will need to be relocated to allow space for a cable riser stand.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Waimauku 33/11 kV TX Replace T1	1.83										1.83

12a.3.6 HANS ZSS REPLACE TRANSFORMERS T1 AND T2

1978 Bonar Long 15/20 MVA ONAN/ONAF transformers at Hans ZSS have DP values that require these two transformers to be replaced within the AMP period. Transformer T2 has a slightly worse DP value than transformer T1 and will be replaced first. The existing transformers are off-tank radiator transformers in transformer enclosures to suit the existing off-tank radiator designs. The winter 2022 peak demand is 23.1 MVA and is forecast to reach 34.3 MVA in 2033. Similar pattern, i.e. off tank radiator, replacement transformers rated 20 MVA (30 MVA 2-hour rating) will be procured and these will be delivered complete with Reg-DA transformer management systems as per Vector's standards.

Because similar footprint transformers, to suit the existing transformer rooms, will be procured, the civil works will include modification of the transformer and radiator pads to suit the new design as well as core drilling of duct routes to suit termination boxes. Because of previous overheating issues, larger louvres will likely be installed, or the roof raised to improve airflow in the transformer enclosure to optimise heat dissipation for the replacement transformers – this will be determined as part of the detail design. The DC system is compliant with Vector's latest standard. The 33 kV oil filled cables that presently terminate directly on to the existing transformers will be terminated to oil-to-XLPE trifurcating stop joints and XLPE tails installed to the new transformer 33 kV termination enclosure.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Hans 33/11 kV TX Replace T2	3.85										4.00
Hans 33/11 kV TX Replace T1			4.02								4.02

12a.3.7 MCNAB ZSS REPLACE TRANSFORMERS T1, T2 AND T3

McNab ZSS is a highly loaded and critical zone substation that supplies a large commercial and industrial customer base (1,269) as well as 5,062 residential customers. The large Illinois Glass recycling plant counts amongst the industrial customers connected to this ZSS. The deteriorating degree of polymerization (DP) values of the 1966 vintage transformers mean that they need to be replaced to ensure the continued reliability of the supply.

The peak demand in 2022 was 37.8 MVA and forecast growth is expected to reach a peak demand of 60.6 MVA in 2033. In line with this forecast peak demand, the project is to replace the three existing 20 MVA transformers with similarly sized 20 MVA (30 MVA 2-hour emergency rating) transformers. However new large industrial customers might require larger transformers to be installed at the time.

The 11 kV switchgear at this ZSS is relatively young and meets Vector's load and short circuit requirements and will remain in service but the transformer impedance will be selected to keep fault levels at the appropriate level as stated in Vector standards. The 33 kV supply cables from Penrose GXP as well as the 11 kV 1-core 630 Al XLPE incomer cables will be retained. The transformers will be delivered with on-board Eberle Reg-DA transformer management systems as per Vector design standards. The transformers will be replaced in sequence so as not to compromise the security of supply at this important commercial and industrial hub. Transformer neutral CTs will be replaced and protection settings revised for improved earth fault protection. Secondary cabling will be replaced as required and full details will be determined as part of the detailed design.

The transformer foundations will be modified to suit the footprint of the new transformers and new masonry reinforced concrete bunds will be installed to oil volume requirements. The transformer bays will be equalized: this will involve a new blast wall between transformers T1 and T2 and replacement of the existing blast wall between T2 and T3. The existing rain shields will most likely be replaced with Vector standard Osbourne rain/ventilation louvres. New primary cable supports will be installed. Existing NERs are fit for purpose and will remain. A second 110 V battery bank will be added to bring this ZSS to Vector standards for high importance zone substations.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
McNab 33/11 kV TX Replace T1	2.40										2.40
McNab 33/11 kV TX Replace T2			0.54	2.96							3.50
McNab 33/11 kV TX Replace T3						2.41					2.41

12a.3.8 MANUREWA REPLACE TRANSFORMER T3

Manurewa ZSS is a three transformer ZSS that feeds a 22-panel fixed pattern 11 kV switchboard installed in 2018. All three transformers are 16 MVA (ONAN) Bonar Long units. T1 and T2 were installed in 1968 and T3 was installed in 1976. Manurewa ZSS supplies 17,271 residential customers, 1,1159 small and medium enterprises and 96 industrial customers. The peak demand in 2022 was 50.6 MVA and is forecast to reach a peak of 68.6 MVA by 2033.

During sampling in July 2020, the oil showed a high-level of moisture and high acid content which shows that fluid oxidation is advancing and the interfacial tension in the oil has reduced. The cellulose in this transformer has degraded and its DP value is 346 and declining at a rate of -23. The insulating oil was streamlined (dry-out process) in December 2020 to improve its reliability for the time being going forward but has been scheduled in the AMP for replacement in FY26. The installed transformer capacity is 48 MVA and N-1 capacity is 32 MVA. However, with the 11 kV backstop that is in place the security limit is such that it has enough headroom for the ZSS to be operated with two transformers during an unplanned failure or while the replacement takes place.

The block and brick panels in the transformer radiator enclosures are unreinforced and will require a rebuild. The works will also include the civil works to construct a new foundation pad for the replacement transformer.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Manurewa 33/11 kV TX Replace T3		0.65	3.14								3.80

12a.3.9 NEWTON ZSS REPLACE TRANSFORMER T1

Newton ZSS is supplied from the Liverpool ZSS 22 kV bus via two 3-core Aluminium PICAS PVC oil-filled cables that terminate directly onto two Turnbull and Jones 12/16 (ONAN/ONAF) MVA 22/11 kV transformers manufactured in 1978. Newton ZSS supplies the south-western corner of Auckland's CBD and has backstop 11 kV circuits to Kingsland and Newmarket ZSSs. This ZSS has a winter peak that reached 18.2 MVA in 2022 and is forecasted to reach 31.0 MVA by 2032.

The existing transformers are off-tank radiator transformers. The replacement transformers will be 20 MVA (30 MVA 2-hour) rated units and will be of a similar off-tank radiator design to suit the layout of the existing enclosures. The two oil-filled cables will be terminated into oil-to-XLPE trifurcating stop joints and XLPE tails terminated in the new transformer 33 kV cable termination enclosures. The 11 kV PILC incomer cables will be replaced with new XLPE tails as per Vector's standards.

The GEC BTV17 11 kV switchgear oil filled switchgear has a short circuit rating of 250 MVA for 3 sec. The switchgear has been ranked in the CBARM model for replacement towards the end of the 10-year planning period. At this point, the asset health of transformer T2 at Newton has not warranted a replacement in the 10-year plan.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Newton 22/11 kV TX Replace T1			0.79	3.51							4.30

12a.3.10 MT WELLINGTON ZSS REPLACE TRANSFORMERS T1 AND T2

Mt Wellington ZSS supplies the large commercial and industrial hub of Mt Wellington. This ZSS is equipped with two 15/20 MVA rated Wilson transformers installed in 1963. Both these transformers are showing a decline in the degree of polymerization. As an interim measure both these transformers underwent Fullers treatment in 2021 to help maintain their integrity and reliability until their replacement.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Mt Wellington 33/11 kV TX Replace T1			0.56	2.90							3.46
Mt Wellington 33/11 kV TX Replace T2				2.09							2.09

12a.3.11 TRANSFORMER REPLACEMENTS IN THE LATTER PART OF THE AMP PERIOD

The forecast table below provides a summary of power transformers that have been identified for replacement in the latter part of this AMP period based on criticality and asset health. Maintenance and monitoring of these transformers will continue and any deterioration in the quality of paper insulation might require a bringing forward of replacement. Mid-life refurbishment more specifically Fuller's earth treatment and oil cleaning (see description further below) will not extend the life of a transformer but will assist to ensure that a transformer at least achieves its standard asset life. It is highly likely that with the pending 2nd interconnecting grid transformer scheduled for installation at Wairau ZSS that the replacement of the 110/33 kV transformers will not go ahead. Their inclusion in this forecast is provisional.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Otara 33/11 kV TX Replace T1					2.48						2.48
Otara 33/11 kV TX Replace T2						2.48					2.48
Wairau 110/33 kV TX Replace T1						2.56					2.56
Wairau 110/33 kV TX Replace T2							2.56				2.56
Te Papapa 33/11 kV TX Replace T1								2.48			2.48

12a.3.12 TRANSFORMER REPAIRS, REFURBISHMENTS AND OIL STREAMING

The lifeblood of a transformer is the insulating oil and during its service life, the oil will degrade. This exposure degrades the quality of the oil which if left unchecked will accelerate the ageing of paper insulation, form sludge which then affects cooling and it also reduces the dielectric withstand capability of the oil. These factors can lead to the premature failure of transformers. The forecasts below are bucket allowances to refurbish and repair older transformers and treat the oil to reduce the risk of degradation of paper insulation. This work will allow Vector to utilise the treated transformers up to their full expected asset lives or as far as possible. The works will be prioritised after scheduled maintenance testing of the older transformers in the fleet. This programme will include some of the transformers described above, ear-marked for replacement to help to maintain their integrity up to the time of replacement.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland ZSS TX Refurb and Repair	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	2.78
Northern ZSS TX Refurb and Repair	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	2.78
Auckland Transformer Oil Streaming	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	2.10
Northern Transformer Oil Streaming	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.23
Total	1.08	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	9.89

12a.3.13 NEUTRAL EARTHING RESISTORS

Neutral earthing resistors (NERs) are used to limit earth fault currents in power systems: their primary purpose is to decrease fault current when an earth fault occurs on the system. For certain customers, to provide uninterrupted supply from two 11 kV bus sections, the fault current has to be limited to maintain it within cable earth screen ratings. Installing NERs however has other consequences such as a rise in the phase to neutral voltages of the unfaulted phases during an earth fault on the third phase: this could cause failures on existing 11 kV surge arrestors. The financial provision in the table below will be used as and where required and will not be applied until or unless a study of the network in question has been undertaken to ascertain the benefits and risks to the chosen installation site.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland neutral earthing resistors	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	3.56
Northern neutral earthing resistors	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	3.56

12a.4 Subtransmission cables

12a.4.1 HILLCREST SUBTRANSMISSION CABLE REPLACEMENT

The subtransmission supply to Hillcrest ZSS is from the Wairau indoor 33 kV switchboard via two 1.5 km underground circuits installed in 1978. Each circuit is composed of early generation XLPE 1-core cables installed in trefoil formation. Recent sheath testing on these cables have returned poor results which is likely a result of water ingress. These cables are deemed to be at risk of failing due to their condition and construction (being early generation XLPE).

On sections of cable route that utilise the road corridor, the cables will be installed under the carriageway due to service congestion on the berms and footpath. Physical access is not as critical for point-to-point subtransmission circuits compared to distribution circuits which need access for mid-feeder switchgear terminations. There is also a lower likelihood of third party strikes if the subtransmission circuit is located under the carriageway.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Hillcrest SUBT cable replacement	4.03										4.03

12a.4.2 WESTFIELD SUBTRANSMISSION CABLE REPLACEMENT

Westfield ZSS is supplied from the Penrose GXP 22 kV bus via three 22 kV rated subtransmission cables (circuits 1, 2 and 3). Circuits 2 and 3 are 3-core copper 240 mm² (0.37 inch²) PICAS oil-filled cables both installed in 1967. Circuit 1 consists of two x 3-core copper PILC SWA cables: one is a 95 mm² (0.15 inch²) cable installed in 1928 and the other is a 150 mm² (0.25 inch²) cable installed in 1941. These two cables existed as separate cable circuits to Westfield in the past before the installation of the oil-filled cables in 1967 but were then, at the time, connected in parallel to become a single (third) subtransmission circuit.

Several faults have occurred on the paralleled cable circuit (#1) but there has not been an increase in the rate of failures over the last number of years. The peak demand at Westfield was 22.2 MVA in summer 2022 and is forecasted to reach 34.6 MVA in 2033. The two oil filled cables (circuits 2 and 3) each have long term cyclic ratings of 17.7 MVA.

Westfield ZSS also has about 10 MVA of 11 kV backstop capacity to adjacent ZSSs: so, with a contingency on circuit 1, the load at Westfield is not at risk and the existing subtransmission and backstop circuits will be able to supply the demand. Based on present asset health and performance, the capacity of the two oil-filled cables and backstop, this replacement project will take place in FY26.

As part of the civil works to replace circuit 1 the second set of trefoil ducts will be installed as future proofing for the replacement of one of the oil-filled cables in the long term. The replacement cable will be 33 kV rated to future proof the circuit for future conversion to the 33 kV bus at Penrose GXP.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Westfield SUBT cable replacement	1.00		12.40								13.40

12a.4.3 EAST TAMAKI SUBTRANSMISSION CABLE REPLACEMENT

The East Tamaki 33 kV subtransmission cables are relatively young XLPE cables. They supply East Tamaki ZSS from Pakuranga GXP. The cables run underwater through a creek and wetland and it appears that water has entered the extruded insulation. Thus far the circuits have been maintained and smaller sections of cable have been replaced but continued insertion of small sections of cable and an increasing number of joints is not good cable asset management practice and in the longer term the sections through the creek and wetland area will have to be replaced with proper water blocked cables.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
East Tamaki SUBT cable replacement			0.28	1.11							1.39

12a.4.4 ONEHUNGA SUBTRANSMISSION CABLE REPLACEMENT

The subtransmission supply to Onehunga ZSS is from Penrose GXP via two underground 3-core copper PILC SWA cables installed in 1963. Small and medium enterprises form a large part of this ZSS's customer base. Vector's asset strategy for PILC circuits over 1000m is to replace the entire circuit rather than undertake piecemeal replacements.

The medium-term plans for the subtransmission network in the area will see the expansion of the existing Transpower Southdown site (Hugo Johnston drive, Penrose) to include a new GXP connection to Vector. This new GXP connection will supply three zone substations (Westfield, Onehunga, and Carbine) currently taking supply from the Penrose GXP. Direct replacement of the aging subtransmission circuits from the Penrose GXP as a result is no longer a cost-effective long-term plan.

This project will include the installation of trefoil ducts and cable for two 33 kV circuits between Onehunga ZSS and the proposed Southdown GXP. A set of trefoil ducts will also be installed between Southdown GXP and the Te Papapa ZSS for a future 33 kV circuit along with smaller ducts for future DTS cables.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Onehunga SUBT cable replacement			10.00	5.39							15.39

12a.4.5 ZONE SUBSTATION CABLE SUPPORT UPGRADE

A recent review into the cause of several switchgear bushing failures determined that they were under significant mechanical stress prior to failing. The cable support systems at these sites did not meet Vector's current standards and were deemed to be a root cause of the bushing failures.

Inadequate cable support systems result in the switchgear bushings supporting the weight of the cable terminations and cable. Indirect alignment of the cable termination with the bushing also induces lateral force on the bushing. Preliminary investigations into the cable support structures at select zone substations has identified sites where the existing cable support system does not meet Vector's current standards, and more are expected to be identified as the investigations progress to all of Vectors zone substations. Cable support system upgrades will include the installation of additional support struts, resizing and replacement of cable clamps, and alignment of the cable termination with the bushing.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
ZSS cable support upgrade			1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	9.60

12a.4.6 LIVERPOOL-KINGSLAND SUBTRANSMISSION CABLE CROSSBONDING PIT RENEWAL

The Liverpool-Kingsland subtransmission circuit is over 3.3km km long and is comprised of three single core cables arranged in trefoil formation. Along the route there are three underground link boxes where the cable screens can be cross connected or "cross-bonded" between cables of different phases. This improvement will maximise the thermal rating of the cables by reducing circulating currents in cable screens. All 11 link box enclosures along the route will be replaced along with the covers.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Live-Kingsland SUBT Cable cross-bonding			0.21	0.62							0.83

12a.4.7 MT ALBERT SUBTRANSMISSION CABLE REPLACEMENT

Mt Albert is a single transformer ZSS supplied from Mt Roskill GXP via a 1960 vintage 3-core 195mm² (0.3 inch) PILC SWA 22 kV cable for the largest part of the route with a 500m section of 300mm² Al 1-core XLPE cable under the 2013 south-western motorway development. The single Bonar Long 12 MVA 22/11 kV transformer installed in 1964 was replaced in FY23 due to poor asset health and a declining rate of DP. The asset health of the existing 22 kV rated PILC cable is reasonable. Its performance is such that the design of the project in FY28 and delivery of the replacement in FY29 is deemed in order. The existing 11 kV backstopping circuits will suffice for this planning period but beyond that, a second subtransmission circuit might be required. Therefore, under the opportunity of a large civil project to install the ducts for this subtransmission replacement, the second set of ducts will be installed to enable a second subtransmission cable to be installed in the long term.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Mt Albert SUBT cable replacement					2.07	4.37					6.44

12a.4.8 NORTHERN SUBTRANSMISSION CABLES REPLACEMENT

The first-generation XLPE cables had taped semiconductor screens which were an ineffective barrier to stop water trees from developing and non-tree retardant XLPE which led to the "water tree growth" in the extruded insulation. Substantial portions of subtransmission cables in the Northern network are of this type and if left unchecked the water trees will lead to failure of the insulation and outages. For the interim, smaller cable-portions are replaced as required but, in the longer term a programme of partial discharge and tan-delta tests will be undertaken and those portions with poor test results will be replaced as whole circuit portions.

The output from the CBARM model typically categorises these cables either as R3 or R4 which are the highest risk categories. The cables currently categorised as R3 often regress into the R4 risk category by the end of the AMP period as their condition deteriorates.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Highbury (52B) SUBT Cable replace			0.20	0.80							1.00
Birkdale (56) SUBT Cable replace	0.52										0.52
Hepburn (38,39,43,44A,49,50) SUBT Cable replace			3.25	1.30	1.85						6.40
Manly (55B) SUBT Cable replace	0.30			3.25							3.55
Sunset road (20) SUBT Cable replace						0.11	0.45				0.56
Triangle road (25&26) SUBT Cable replace						0.22	0.87				1.09
Takapuna SUBT Cable replace	0.05										0.05
Wairau (52A) SUBT Cable replace							0.41	1.64			2.05

Silverdale (55A) SUBT Cable replace								0.16	0.65		0.81
Bush Road (63) SUBT Cable replace			1.38								1.38
Total	0.87		4.83	5.35	1.85	0.33	1.73	1.80	0.65		17.41

12a.5 Distribution equipment

12a.5.1 LV NETWORK REPLACEMENT

Vector's approach to replacement of assets in the LV distribution network is condition rather than age based. Vector has previously had programmes to replace specific population type assets in the LV network but has not had a proactive replacement programme for the LV distribution system in general. The LV network replacement programme will target assets identified during network inspections as being in a deteriorated and/or unsafe condition. LV asset replacements are normally done like for like but considerations will be made to enhance safety and demand growth from EV charging and distributed generation. Enhancements will also take consideration of the impact of climate change.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland LV network replacement			1.74	1.79	1.84	1.90	1.95	1.95	1.95	1.95	15.08
Northern LV network replacement			1.74	1.79	1.84	1.90	1.95	1.95	1.95	1.95	15.08
Total			3.47	3.58	3.68	3.80	3.90	3.90	3.90	3.90	30.17

12a.6 Auxiliary systems

12a.6.1 DC SYSTEMS

DC systems must be available 24/7 to ensure safe and secure zone substation asset operation for continuous power supply to customers. The failure of a DC charger and a subsequent loss of its DC system, therefore, has a zone substation outage SAIDI risk. Vector currently has a total of 335 110 V DC systems in service within zone substations, communications sites and several distribution substations.

Of these, 9 Northern and 19 Auckland network Benning 110 V chargers have reached end-of-life, are non-vendor supported with no spares available and with several recent failures consuming all remaining Vector spares. A replacement programme commenced with sites prioritised for replacement based on the criticality of connected customers, plus age, condition and failure history of the charger and this will continue in the AMP period. The project outcome ensures continued successful operation of zone substation control, protection, interlocking and other essential equipment that is reliant on a correctly functioning DC system. The replacement programme achieves Vector's standard, network wide.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland DC replacement	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.67
Northern DC replacement	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.67
Total	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	1.34

12a.6.2 SECURITY, ACCESS AND FIRE PROTECTION

Since 2016 NZS 7901 Public Safety annual audits by Telarc provide an independent safety assessment of randomly selected distribution asset and zone substation perimeter earthing, signage, safety and security of access. A decreased trend of severity and occurrence for security risk was gained in 2019 following workshops held with the FSPs on how to improve planned maintenance inspections, such as looking outward as well as inward from the perimeter and Vector responding quicker to approve projects to address security concerns raised by the FSPs.

Although entry incidents are very rare, we continually monitor the benefit of grounds surveillance cameras now thermal imaging detection is maturing in functionality. All buildings are monitored with intruder detection.

For site security, to minimise the risk of unauthorised entry the program of perimeter fencing upgrades continues from its inception in FY20 for critical customer sites and those typically in rural and industrial areas with their heightened potential risk of unobserved perimeter entry. Additionally, the Gallagher Cardax security system requires regular upgrades and its end of life controller replacement project were completed in FY22.

While fires in zone substations are rare the consequences can be very serious. The objectives of fire protection are clearly defined in Vector guideline "ENG-0028, Fire protection in zone substations" and asset strategy EAA600 [1]. All detection systems connected to the zone substation Fire Panel must comply with NZS4512 and maintenance standard ESM603 activities to ensure compliance is met during their installed life. Our program of replacing legacy fire panels to current standards will be completed in FY22, while detection systems will continue their planned replacement into FY23.

Radio huts which the northern network SCADA and EOC are dependent on, require new passive fire detection, and although the risk is low (hence an FY24 date) due to no cable joints for the cables within them, the seven minor tunnels will benefit from fire detection.

The budget allows for progressing legacy site-by-site targeted improvements to meet new standards for zone substation security including perimeter fencing, and fire protection upgrades, for which Design Standard ESE703 applies.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland Fire and Security upgrade		1.14	0.70	0.20	0.20	0.20	0.20	0.20	0.20	0.20	3.24
Northern Fire and Security upgrade		1.20	1.20	0.35	0.35	0.35	0.35	0.35	0.35	0.35	4.85
Total		2.34	1.90	0.55	0.55	0.55	0.55	0.55	0.55	0.55	8.09

12a.6.3 HEATING, VENTILATION AND AIR CONDITIONING

Increasing ambient temperatures and the duration of these over summer has in recent years increased the need to provide cool dry air via heat pumps. New systems are required at up to six zone substation sites p.a. in addition to the usual new installs for ARP and RNF switchgear or building replacement projects. Sites are prioritised by their temperature/humidity excursions outside the specified measurement requirements of Vector standard ESM603 Auxiliary Systems.

Heat pumps are the industry standard to cost effectively control the zone substation and other facility building internal atmosphere temperature and humidity to ensure IEDs and metal clad switchgear operate within manufacturer and their IEC standards recommended parameters. The positive air pressure systems draw filtered external air into the building to pressurise and provide continuous air changes as controls to minimise dust entry, stale air and to inhibit corrosion, rust and deterioration.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland ZSS HVAC installations	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.23
Northern ZSS HVAC installations	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.23
Total	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	4.45

12a.7 Infrastructure and facilities

12a.7.1 PENROSE TUNNEL

The Penrose to Hobson Tunnel contains Vector's 110 kV subtransmission cables from Transpower Penrose GXP to Liverpool and 33 kV cables to Newmarket ZSSs as well as the TP 220 kV NAaN cable from Penrose 220 kV GXP to Hobson GXP. The tunnel also contains 22 kV express feeder interconnectors between Liverpool ZSS and Hobson ZSS. Transpower has shared access rights for the tunnel. The tunnel was commissioned in 2001 and the auxiliary systems necessary for personnel safety and performance of the power cables are now progressively starting to fail having reached the end of life. To also ensure maintenance and emergency access these systems cannot be run to failure. This includes the service train within the tunnel, which is subject to New Zealand Transport Authority regulations for rail safety. Furthermore, the tunnel is classed as a confined space that requires strict entry requirements and these specified auxiliary systems to be operational 24/7.

For an auxiliary system failure, there is a health and safety risk, which could result in the Asset Safety Incident Rate being increased. To ensure the integrity and safe operation of personnel and plant within this strategic asset there is a need to replace and refurbish auxiliary systems inclusive of the rail and its anchor systems.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Tunnel - Ventilation Motor Replace				0.34							0.34
Tunnel - Control Room refurb			0.23								0.23
Tunnel - Train, Generator, Rolling Stock Replace	0.22							0.52			0.73
Tunnel - Ventilation VSD Replace					0.23						0.23

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Tunnel - Sump pump replace	0.13				0.12			0.11			0.36
Tunnel - Newmarket Plant Room Exterior Replace					0.06						0.06
Tunnel - Newmarket Lift replace			0.90								0.90
Tunnel - Sump pump control system replace					0.12						0.12
Tunnel - Atmospheric Sensors Replace							0.28				0.28
Tunnel - Rail Track and Anchor Replace	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.55
Tunnel - Newmarket Egress Ladder Compliance replace	0.22	0.22									0.45
Tunnel - Fire Main Valve Replace	0.16										0.16
Tunnel - PLC Firmware Upgrade		0.23						0.28			0.51
Tunnel - Airlock Security replace	0.17										0.17
Total	0.96	0.50	1.18	0.40	0.58	0.06	0.33	0.96	0.06	0.06	5.08

12a.7.2 LIGHTING AND EMERGENCY LIGHTING UPGRADES

Vector's design standard ESE703 Zone substation building services follow the guidelines set out by the Department of Labour and NZS 1680.2, interior lighting – recommended illuminances. The investment forecast under this item is for the upgrade of normal and emergency lighting in legacy zone substations that do not comply with Vector's design standard and there is thus a risk of workplace harm due to insufficient lighting or lack of emergency lighting.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland ZSSs lighting upgrades	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.67
Northern ZSSs lighting upgrades	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.67
Total	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	3.34

12a.7.3 ZONE SUBSTATIONS CIVIL AND STRUCTURAL UPGRADES

Several ageing zone substation buildings exist in our network and although these are maintained following a rigorous and structured maintenance regime there are instances where normal maintenance is simply not enough to remedy larger civil and structural defects. In such cases, a capital project must be undertaken to remedy any issues. Examples of larger defects are seismic non-compliance and deterioration of a building due to soil movement where structural strengthening is then required. There are also instances where deficient construction methodologies, e.g. improperly installed monolithic construction, was used in the not too distant past to construct some of our substations and these now require extensive repair work beyond normal maintenance.

Furthermore, switchroom and transformer bay roofing inspections and sporadic leakages are now driving the need for a full roof replacement programme to avoid the risk of metal clad primary plant failure in switch rooms and the need to add SEPA systems to transformer bunds. This is primarily for light timber frame galvanized steel roofing. Well maintained legacy concrete roofed buildings only require a hot-bitumastic reseal which outlives alternatives of polymer sheet materials by tens of years for similar cost.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland ZSS civil structural upgrades		0.20	0.56	1.11	0.17	0.17	0.17	0.17	0.17	0.17	2.87
Northern ZSS civil structural upgrades		0.20	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.56
Total		0.40	0.72	1.28	0.33	0.33	0.33	0.33	0.33	0.33	4.41

12a.7.4 ZONE SUBSTATIONS EARTHING UPGRADES

Vectors zone substation earthing systems must limit the touch and step potential rises that occur in the event of a fault on their network. This is to protect visitors and workers within the zone substation compound as well as the nearby public outside the fence. Corroded joints above and below the ground will be repaired and any bonds between stock fencing and the substation fence will be removed. Considerations will also be made for any fault level changes that have occurred since the earthing system was initially designed and installed during the construction of the zone substation.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland ZSS Earthing upgrades	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.23
Northern ZSS Earthing upgrades	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.23
Total	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	4.45

12a.8 Protection and control

12a.8.1 SIEMENS SIPROTEC NUMERICAL RELAYS REPLACE

The Siemens Siprotec 3 range of numerical protection relays is the first-generation Siprotec based numerical relays installed in Vector's network starting in 1998. The expected asset life of this generation of numerical relay is ~15 to 20 years. The Siprotec 3 numerical relays are a discontinued line and replacement parts are very expensive and some parts are simply not available for this generation of numerical relays. Replacement is more economical than repair and the devices will be replaced with modern numerical relays. This programme will also include the replacement of Siprotec 4 relays that use copper pilot wire for differential protection or where possible, retain the Siprotec 4 relays and replace the communications converter so that the Siprotec 4 relays can be retained for use with fibre optic pilot cables.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland Siprotec 3 relays replace	1.00	1.00	0.59	0.62	0.66	0.88	0.11	0.31	0.20	0.15	5.52
Auckland numerical SIP4 on pilot wire		0.25	1.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	2.45
Total	1.00	1.25	1.74	0.77	0.81	1.03	0.26	0.46	0.35	0.30	7.97

12a.8.2 AUCKLAND AND NORTHERN ELECTRO-MECHANICAL RELAYS REPLACEMENT

Vector's population of electro-mechanical relays is around 60 years old and there remains eight zone substations with this type of protection relays. The electro-mechanical relay population (together with static relays – described elsewhere) is about 23% of the total relay population in Vector's network. Electro-mechanical relays, although reliable, provide only basic overcurrent and earth fault protection and has no data storage or recording ability which makes analysis of faults onerous. Furthermore, these relays are not supervised which means that if they fail none will be aware of such failure of the relay until a network fault occurs and an upstream trip is required to clear the fault: such a scenario is not tenable as it could lead to a much larger outage and commensurate high SAIDI. This population of relays also do not have the ability for definite time protection settings to be implemented which is required for increased safety of our large rural overhead networks and cannot be remotely accessed for data interrogation or to load revised settings. The electro-mechanical protection relays will be replaced with modern numerical relays.

The program below applies to zone substations where a switchgear replacement is not planned within five years. Where a switchgear replacement is scheduled within five years, a protection relay replacement will be delayed to then be undertaken in concert with the switchgear replacement project.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland electro-mechanical relays replace	0.50	0.50	0.57	0.69	0.64	0.88	0.49	0.66	0.20	0.16	5.29
Northern electro-mechanical relays replace	0.42	0.41	0.41	0.49	0.39	0.45	0.32	0.33	0.20	0.15	3.57
Total	0.92	0.91	0.98	1.18	1.03	1.33	0.81	0.98	0.40	0.31	8.85

12a.8.3 NORTHERN STATIC 1ST GENERATION NUMERICAL RELAYS REPLACE

Static (1st generation numerical) relays form about 2% of Vector's relay population. These relays were the first-generation electronic relays installed in place of electro-mechanical relays in protection schemes in Vector's network (and the world over), about 25 to 30 years ago.

Although they have added setting functionality over and above electro-mechanical relays their reliability has not been to expectation. The static relay population consists of ABB relays used for underfrequency load shedding and Micom general protection relays all in the Northern network in five zone substations namely Bush Rd, Simpson Rd, Hillcrest, Henderson Valley and East Coast Rd. Several maloperations of this type of relay have occurred. The manufacturing of static relay has halted many years ago and there is no vendor support. The relays will be replaced with modern numerical relays and the program is planned to commence in FY24.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Northern Static 1stGen Numerical Relays Replace	0.50	0.47	0.59	0.44	0.50	0.32	0.33	0.16	0.16	0.16	3.61

12a.8.4 AUCKLAND AND NORTHERN TRANSFORMER MANAGEMENT SYSTEMS REPLACE

Transformer management systems (TMS) provide continuous and automatic voltage regulation ensuring voltage regulatory quality supply requirement are met as well as continuous thermal monitoring of transformers and cooling system controls. Of the 209 TMS systems in operation, 74% are modern numerical devices. The remainder of the TMS systems is a mix of electro-mechanical, static and PLC devices. Several of the electro-mechanical devices are between 40 and 60 years old and there is no vendor support or spares available. The remaining PLC based TMS systems has exhibited an increasing failure rate in recent years. The program below forecasts the replacement of the remaining electro-mechanical and PLC based TMS systems with either Reg-DA or SEL-2414 numerical TMS systems in 25 zone substations. The focus of this forecast is those ZSSs where a transformer or switchgear replacement will not be undertaken in the next five years. Where a switchgear or transformer replacement is scheduled in this AMP, the TMS systems will be included in the larger project.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland TMS replacements	0.30	0.30	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	3.80
Northern TMS replacements	0.30	0.30	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	3.80
Total	0.60	0.60	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	7.60

12a.8.5 AUCKLAND AND NORTHERN POWER QUALITY METER REPLACEMENTS

Power Quality Meters (PQM) monitor in real time the condition of the power system and analyse the power quality by an enterprise software application. PQMs locally stores reports generated by the system and makes the information available when required and monitor frequency events affecting the Vector network. PQM meters are also used to initiate interruptible load via the ripple systems to reduce peak demand.

The expected asset life for a PQM meter is ~15 years and approximately 23 have exceeded that period and the latest operating software upgrades are not compatible with these previous generations PQM meters in the network. The exact priority list for the PQM replacement is being worked through in detail and the first sites in which replacements will be undertaken in this AMP period are Rosebank ZSS, Hepburn GXP, Lichfield ZSS, Hobson 110 kV ZSS and Wellsford GXP.

The forecast below makes provision for the afore-mentioned sites and the remaining 18 (of 23) sites at which replacement will take place in the 10- year forecast period.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland PQM replacements	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	1.11
Northern PQM replacements	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.45
Total	0.21	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	2.56

12a.8.6 NORTHERN EXTENDED RESERVES UNDER-FREQUENCY INSTALLATIONS

In terms of the Electricity Industry Participation Code and the requirements of the System Operator (SO), Vector is obliged to provide under frequency load shedding under "load blocks" as defined by the SO for underfrequency events. PQM meters, described above, provide non-UF load shedding, for example, to reduce peak demand and/or to defer capital investment: by reducing peak demand in the network which then defers the need for network reinforcement but do not have the high-resolution capability to initiate under frequency load shedding as is now required by the System Operator.

This program of work is for the installation of SEL 751 IEDs that provides under frequency load shedding where very fast responses with a ride through protection is required. The requirements for underfrequency events have become more stringent under recent FCAS regulations and requires devices that have the functionality for rapid capture and control of load shedding on under/over frequency events. These IEDs also have the functionality to "ride through" <49.2 Hz under frequency events that are shorter than 100 milliseconds.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Northern Extended Reserves UF Relays Install	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	1.11

12a.8.7 AUCKLAND AND NORTHERN LOCAL AREA NETWORK SWITCH REPLACEMENT

Vector, some years ago, adopted an IEC standard and internationally recognised open communications architecture that would allow different devices located within a zone substation to integrate seamlessly and communicate with the SCADA control system. The substation local area network (LAN) is based on a redundant optical ethernet architecture compliant with IEC 61850 Standards. The LAN enables the co-ordination of protection, automation, monitoring, metering and control functions using network switches to the wide network and then to the SCADA master station.

The existing Vector standard Ruggedcom RSG2100 models are restricted to a maximum number of 20 ports. These Ethernet switches do not support the latest redundancy protocols and Ethernet switches with a higher port density, could reduce the total number of switches required at a substation. An investigation into alternatives to the Ruggedcom RSG2100 switches is on-going with the first trials expected to commence in the second half of FY24.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland LAN switches replace	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.50
Northern LAN switches replace	0.21	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.55
Total	0.36	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.01

12a.8.8 AUKCLAND AND NORTHERN RTU REPLACEMENT

The RTUs located at our zone substations provide an essential part of the SCADA system to collect status information from the site and allow remote control of the auxiliary and facilities plant at the site. The maximum anticipated life of an RTU is 20 years. As an RTU approaches the end of life, reliability suffers, requiring more frequent maintenance. Also, older RTUs are no longer supported by suppliers and spares are difficult to get hold of. When an RTU fails, situational awareness of what is happening at the site is lost: the EOC is then unable to receive updates of events from the site or remote control equipment. Hence, the EOC controller is unable to effectively respond to any emerging contingency.

This programme of work is for the replacement of substation RTUs and distribution controllers. The substation and distribution control RTU fleets consist of a mixture of ABB RTUs for 11k V distribution switches and, GPT Plessey, Foxboro, SEL 2440 and SEL 2411 RTUs in zone substations. The first-generation Foxboro and GPT Plessey range of RTUs are no longer technically supported and production has halted a few years ago. These RTUs will be replaced.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland RTUs replace	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.67
Northern RTUs replace	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.67
Total	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	3.34

12a.8.9 AUCKLAND AND NORTHERN WAN ROUTERS AND COMS CABLES UPGRADES

The Zone Substation's Local Area Network (LAN) can communicate with the Vector Wide Area Network (WAN) using Routers. The Routers ensure that SCADA data traffic is prioritised and relayed across the Vector WAN to the appropriate destinations. Routers also use dynamic routing techniques to help to reduce network traffic. The programme to replace Cisco 2811 routers with new Vector standard CGR2010 routers commenced in FY18 and this programme will continue to completion and a rollover programme initiated as required.

The copper pilot population is 50 plus years old and is simply not suitable for the high bandwidth requirements for the energy network of the future. The copper pilot cable also has serious reliability issues and requires lengthy periods for fault finding and repair. We have embarked on a programme of works to replace the copper pilot cable fleet with fibre optic communications channels to improve reliability and resilience. This programme of work that commenced in FY18 will continue to completion. Under this provision, the network will also be thoroughly assessed to identify sites with reduced redundancy or connection points that could cause bottlenecks in the future. Chorus copper ADSL/HSNS connections will be replaced with a fibre optic equivalent.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
AKL WAN routers, coms upgrade	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.45
NTHN WAN routers, coms upgrade	0.33	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	2.34
Total	0.43	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	3.79

12a.8.10 AUCKLAND AND NORTHERN COMMUNICATIONS UPGRADE IN DISTRIBUTION ASSETS

Vector has ~500 distribution switches in the Auckland and Northern networks that use cellular communications infrastructure for SCADA and engineering communications to enable remote control of the distribution switches. The distribution switches are a combination of pole top devices (e.g. reclosers, sectionalisers, disconnectors etc.) and ground mounted switches, mostly ring main units. Many of the routers have reached the end of life and low reliability and low availability are causing undue SAIDI.

Under this programme of works Sarian and Digi WR41 routers will be replaced and optimized antennae combinations will be installed. This programme of works commenced in FY22, rolled through FY23 and will continue over the AMP 2023 10 year planning period. This programme includes provision for trials and proof of concept testing of 5G based router options.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
AKL coms upgrade in distribution assets	0.08	0.05	0.05	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.23
NTHN coms upgrade in distribution assets	0.08	0.08	0.05	0.10	0.15	0.15	0.10	0.10	0.10	0.10	1.01
Total	0.16	0.13	0.10	0.25	0.30	0.30	0.25	0.25	0.25	0.25	2.24

12a.8.11 ARC FLASH DETECTION RETROFIT IN EXISTING SWITCHGEAR

The installation of arc-flash sensors on the inside of a switchgear panel together with an arc-flash relay can substantially reduce the amount of incident energy should an arc-flash occur, making switch rooms safer for personal to work in and visit. Early detection of arc flash also reduces the scale of collateral damage of plant. At selected sites, arc detection sensors will be installed in the cable boxes with VAMP 125 arc detection relays. Switchboards identified in Vector's ZSS switchboard replacement programme will be excluded from this programme as arc flash protection will be included in the replacement switchgear delivery scope.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland Arc Detection Retrofit	0.42	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	4.02
Northern Arc Detection Retrofit	0.38	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	3.22
Total	0.80	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	7.24

12a.8.12 AUFLS 4-BLOCK SCHEME ENABLE

The automatic under-frequency load shedding (AUFLS) scheme plays a critical role in preventing cascading asset failures on the national grid following a significant loss of generation. The Electricity Authority has amended the Electricity Industry Participation Code to enable the transition of the AUFLS provision in the North Island from a 2-block scheme to a 4-block scheme. Project expenditure will be for engaging external service providers to upgrade protection settings, prepare testing documentation and commissioning changes on site.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Auckland AUFLS 4 Block Scheme enable	0.56	0.56									1.11
Northern AUFLS 4 Block Scheme enable	0.56	0.56									1.11
Total	1.11	1.11									2.23

12a.8.13 SMALLER UPGRADE PROJECTS TO IMPROVE PROTECTION AND COMMUNICATIONS

The following is a summary forecast table of smaller scale projects that will be undertaken during the AMP period to improve protection, reduce the risk of spurious tripping due to mutual coupling and improve communications.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Northern Protection signalling improvement mutual coupling	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	1.70
Northern DMR improvements	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.49
Auckland Clock Synchronisation improvements	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.50
Northern Clock Synchronisation improvements	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	1.60
Auckland BESS Controller Standardisation and Improvement	0.12	0.12	0.12	0.70	0.70	0.70	0.50	0.50	0.50	0.50	4.46
Northern BESS Controller Standardisation and Improvement	1.30	1.30	1.30	0.80	0.80	0.80	0.50	0.50	0.50	0.50	8.30
Total	2.04	2.05	2.05	2.13	2.13	2.13	1.63	1.63	1.63	1.63	19.05

SECTION 13

Asset relocations

13 –Asset relocations

13.1 Overview

The growth and improvement of other asset types such as water infrastructure, roads infrastructure, rail, sewerage, stormwater as examples result in the relocation of Vector's assets. This Section explains our approach to relocating assets on behalf of customers, other utilities or requiring authorities and describes typical relocation works, our process for managing these works, and how they are funded.

13.2 Asset relocation requests

One of Vector's objectives when planning projects and compiling the capital budget is to identify the need to relocate Vector assets when reasonably required by third parties. Vector is obliged to relocate its assets by Sections 32, 33 and 35 of the Electricity Act 1992, Section 54 of the Government Roading Powers Act 1989 and Sections 147A and 147B of the Telecommunications Act 2001 and by the specific terms of licences or easements under Sections 34 and 35 of the New Zealand Railways Corporation Act 1981.

Relocations generally occur when infrastructure projects are initiated by road or rail corridor managers, e.g. Auckland Council or Auckland Transport (AT), New Zealand Transport Agency (NZTA) and to a lesser extent KiwiRail. Other utility providers such as Transpower, Chorus and Watercare can also initiate asset relocation projects. The process and funding of such relocation works is governed by the relevant Acts as listed above.

The timing and scope of relocation projects are driven by third parties and as a result of this Vector often has less advance notice of relocation projects and / or detailed scope compared to projects initiated from within Vector. The forecasting and timing of capital spend for relocation works are thus at a high level and preliminary in many cases. Asset relocations can vary from large extensive multi-million dollar projects to small and minor relocations such as a pole replacement.

13.3 Asset relocation growth

Long term and consistent growth in the Auckland region have resulted in an increased demand for transport corridor owner requests for asset relocations. The central rail link is a case in point where Vector assets, to the tune of millions of dollars, had to be relocated to make way for the underground rail tunnels and continues to be relocated to make way for new underground stations. Extensive motorway upgrades by NZTA is continuing and the construction of bus lanes and cycle lanes, installation of linear parks and minor road upgrades by AT are continuing and the list is growing.

Vector continues to liaise closely with transport corridor owners and private sub-division developers to understand the scope and timing of their future works and to look to integrate Vector initiated works where appropriate to make allowance for future grid exit points, new zone substations and transmission corridors, in alignment with our Asset Management Objectives. It is vital for Vector to understand how the corridor works and/or new subdivisions will impact on the network to ensure that we can maintain an integrated network to the satisfaction of our customers and stakeholders, while delivering on our Asset Management Objectives.

The Unitary Plan rule change (plan change 78) for urban housing intensification permits multi-level buildings up to three stories high to be constructed on standard land sections that previously contained single level dwellings set back from the road front. The permitted multiple dwellings combined with shallow yard setbacks and their increased heights are now becoming a contributor to increasing breaches of minimum distances to existing overhead lines. This in turn triggers relocations of portions of overhead power lines at the cost of developers. Vector is continuing- to engage with a number of parties to raise awareness about close approach risks, particularly working and building near the network, and to find a solution to the problem of increasing numbers of permitted development occurring in breach of safe clearances detailed in ECP 34 - New Zealand Electrical Code of Practice for Electrical Safe Distances (NZECP 34:2001).

13.4 Managing relocation works

Vector's asset relocation works are generally smaller in scale, both in terms of scope and cost, when compared to transport corridor infrastructure works (usually less than 5% of the total project cost). Relocation projects are driven by the wider civil works programme of third parties, and this can impact the timing and duration of power outages our customers experience during the relocation works due to the requirements of traffic management, road closures etc. These parameters are outside of Vector's control and if not managed carefully and in detail can introduce inefficiencies and cost to the projects.

Vector's electricity network assets are generally installed in local authority owned and managed transport corridors in accordance with the Electricity Act 1992, Gas Act 1992 and the Telecommunications Act 2001. Access to NZTA's motorways and state highways are subject to the provisions of the above legislation and the Government Roading Powers Act 1989. On Kiwirail corridors, Vector is required to sign a licence agreement (Kiwirail Deed of Grant) and contribute the full cost of the relocation works plus payment of an annual fee.

13.4.1 RELOCATIONS OF VECTOR ASSETS

Where the transport corridor owner requests Vector's assets to be relocated, the cost allocation of such relocations are governed by legislation (Electricity Act 1992, Gas Act 1992, Government Roading Powers Act 1989, and the Utilities Access Act 2010). In all cases, Vector pays for any betterment works if and when Vector elects to improve its assets under relocation works.

13.4.2 INFRASTRUCTURE AGREEMENTS AND SUCCESSFUL RELOCATION PROJECT OUTCOMES

The details of the Vector assets that will be relocated are recorded in Vector's standard Infrastructure Agreement. The financial contribution by the third party and any betterment costs that Vector will carry are also defined in the Infrastructure Agreement. It furthermore includes:

- an initial estimate for the cost and cost allocation of the relocation works (final cost allocation is based on the actual total cost of the works)
- a methodology of how the works will be delivered; and
- the payment of the actual costs incurred (the contribution) is undertaken at agreed milestones

Vector does not enter into agreements with the third party or corridor owner's contractors but will liaise with the contractors during the delivery of a relocation project to coordinate the works to ensure effective delivery. To ensure successful relocation project outcomes, an experienced Vector project manager is involved from the early planning stage of relocation projects and then throughout the project delivery phase. This leads to the project manager taking a proactive role in ensuring the construction contractor(s), both for the third party and Vector, pays due consideration to the key outcomes relating to the Vector activities. This is achieved through clear communication of Vector's expectations and reinforcing them throughout the project. Creating and managing the right level of communication between the corridor owner and the civil contractor/construction contractor helps to deliver the works to the agreed standard. Variations are usually initiated by the entity requesting asset relocation and are governed by a proper scope change process that involves documentation, costing and agreement between Vector and the third party.

13.5 Current project summary

Table 13-1 presents a summary of projects where relocations will be required with a value of >$1M which are either in progress or anticipated to be undertaken in the near term over the AMP period.

THIRD PARTY	DESCRIPTION
Kainga Ora Urban Rejuvenation Projects	Relocation of Vector services in the Auckland network will be undertaken in urban redevelopments in Oranga, Mangere, Tamaki and Mt Roskill In the Northern network, relocations will be undertaken in the large urban rejuvenation in Northcote
Auckland Transport (AT) and/or NZTA Projects	AUCKLAND NETWORK: • Auckland-Manukau Eastern Transport Initiative (AMETI)-Stages 2,3,4 • AMETI – stages EB3C and EB4i • A number of cycleway projects • Bellingham Rd, Flatbush – road improvements • Carrington Rd, Mt Albert – road widening • Mill Rd, Takanini – rebuilding of road • Te Ha Noa (Victoria St) in the CBD- road improvements • Wellesley St, Auckland CBD – construction of bus lanes • Relocation works for the Central Rail Link in the Auckland CBD is ongoing as required NORTHERN NETWORK: • Dome Valley Safe Roads project • Glenvar and East Coast Rd, Torbay – road widening and improvements • Highgate Bridge improvements • Lake Rd, Devonport Peninsula – improvement and cycleways • Lincoln Rd, Te Atatu - road improvements • Rosedale Rd, Rosedale, North Shore – busway construction • State Highway 16 Stage 1, including Access Rd and Station Rd – road improvements
Major Government and Local Government Works	Auckland Light Rail is in the preliminary stages of discussion relocations

TABLE 13-1: CURRENT RELOCATION PROJECT SUMMARY (>$1M)

13.6 Forecast expenditure - relocations

The timing and scope of relocation projects are driven by third parties and their project timing and schedule. The initial financial forecasts are always at a high level and as the project and its design and scheduling becomes more detailed, our CAPEX forecasts will become more accurate. The expenditure profile histogram below is based on our knowledge of FY24 asset relocations projects and incorporates our best indicator of CAPEX spend for the 10 year AMP period. The initial years will have the highest level of pricing confidence but for the latter years the pricing confidence will be at a lower level of accuracy.

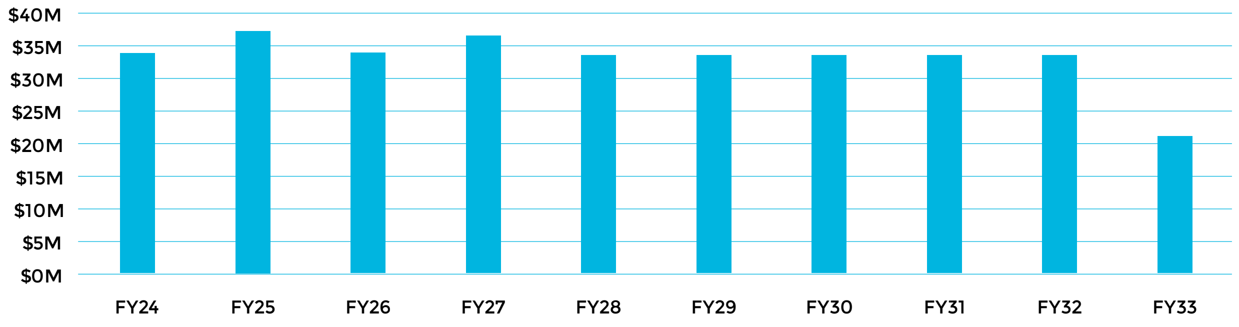


FIGURE 13.1: FORECAST EXPENDITURE - ASSET RELOCATION

SECTION 14

Non-network assets

14 – Non-network assets

14.1 Overview

As part of Vector's Symphony strategy, digital platforms and tools are critical enablers. Vector is investing in Digital capabilities to establish, operate and support these platforms given their importance to core network operations. To do this effectively, an operating model (based on standards) was established that divided the electricity distribution business into its core functions - these have been labelled Value Streams.

Value Streams have key outcomes they set out to achieve, twenty-four-month roadmaps that chart out forecasted investments, and cross functional teams that plan and execute work on a quarterly basis. The construct of these cross functional teams delivers effective solutions, as well as skilled and experienced people to operate and support the solutions once they are live.

In addition to the Value Streams and their respective roadmaps, planning has been significantly informed by the Future Network Roadmap, as outlined in Section 2. The Pathway and Planks that have been defined, have a significant basis in non-network development. As part of this, we have outlined the activities which have been identified as needing to be undertaken, on the basis of executing our Future Network Roadmap and achieving our Symphony Strategy.

In this section, we define the context for our increasing investment in Digital, our major programmes/projects, and definitions and focus areas for each of the Value Streams. As uncertainty increases the further we forecast, the Value Stream model allows us to use roadmaps to define the initial 24-36 months to some level of detail with following years indicating a level of forecasted investment by Value Stream. As roadmaps are updated, they provide increasing visibility to the latter years of the investment forecast.

14.2 Asset management objectives

The asset management objectives that are addressed through our non-network investments are set out in the table below:

FOCUS AREA	OBJECTIVES
Safety, Environment and Network Resilience	• Preventing harm to workers, contractors and the public through our work practices and assets. • Ensure health and 'safety always' is at the forefront of decision making for the business. • Comply with relevant safety and environmental legislation, regulation and planning requirements. • All staff are competent and trained in their applicable roles with the right equipment available to work safely and effectively. • Asset management activities align with environmentally responsible and sustainable behaviours, in line with industry best practice, enabling wider emissions reductions. • Minimise the impact on the environment with regards to our assets and work practices. • Proactively manage network security, which includes adequacy, reliability and resilience (including managing the growing impact of climate change).
Customers and Stakeholders	• Enable customers' future energy and technology choices. • Provide a high-quality customer service experience across all interactions. • Listen to and learn from our customers to ensure our service offering aligns with customer expectations. • Consider the impact of our operational decisions on customers and minimise the disruption of planned outages and unplanned outage response times.
Network Performance & Operations	• Comply with regulatory quality standards set out in the DPP3 Determination. • Maintain accurate and comprehensive information management systems to drive continuous improvement of our asset health database and information records and meet regulatory reporting obligations. • Continual improvement of our asset management system and alignment to ISO 55001. • Strive to optimise asset lifecycle performance through increased asset standardisation, clear maintenance regimes and the development of fact based investment profiling. • Utilise clear business cases processes, integrate risk management and complete post investment reviews to inform our decision making and analysis. • Maintain compliance with Security of Supply Standards through risk identification and mitigation. • Expand our asset strategies to both incorporate new technologies and optimise the use of existing technologies to enable future resilience and customer choice. • Collaborate with teams throughout Vector to leverage different thinking, skillsets and asset management capabilities. • Ensure continuous improvement by reviewing and investigating performance and embedding learnings. • Manage performance of field service providers through effective commercial arrangements and regular review.
Future Energy Network	• Prepare the network for future changes that will be driven by: – technology: increased active customer participation, distributed energy resource (DER) integration, DER orchestration etc. – environment: climate disruption and network resilience – customer: decarbonisation of the economy, electrification of transport, etc. – operations: transition to distribution system operator model and whole of system planning

FOCUS AREA	OBJECTIVES
	• Prioritise network flexibility to meet changing customer needs and facilitate an affordable transition to a decarbonised economy including DER orchestration through third party flex traders and retailers. • Facilitate customer adoption of new technology while ensuring a resilient and efficient network. • Treat data as an asset, protect it appropriately and manage its use in accordance with its criticality to customers and the network. • Develop digital and data platforms to meet changing customer needs and enable the future network in partnership with new entrants to the energy market. • Improve our visibility of, and ability to control, the LV network including management of the information required. • Collaborate with the industry, partners, thought leaders and subject matter experts to ensure Vector remains at the leading edge of future energy solutions.

TABLE 14-1: ALIGNMENT TO ASSET MANAGEMENT OBJECTIVES

14.3 Non-network assets

14.3.1 INFORMATION SYSTEMS, PROCESSES AND DATA

Within Vector's suite of Information Systems (outlined in Section 6.6.), and the associated processes and data sources, there are a number of areas and opportunities we have identified where the use of digital technology can improve the way we plan for, monitor, control and manage our assets.

The proposed investment in the upcoming years in enabling non-network digital systems, processes and information management will ensure Vector has the capability and tools required to deliver to our Asset Management Objectives.

Section 2 outlined the Future Network Roadmap Framework, and a significant amount of effort has gone in to assessing the non-network activities required in order to support this strategy. Across the three Pathways identified (Customer, Technical and Enabling) there are a number of Planks which require significant non-network investment in order to achieve the desired outcomes. The significance of and activities which are required within the relevant Planks are outlined below.

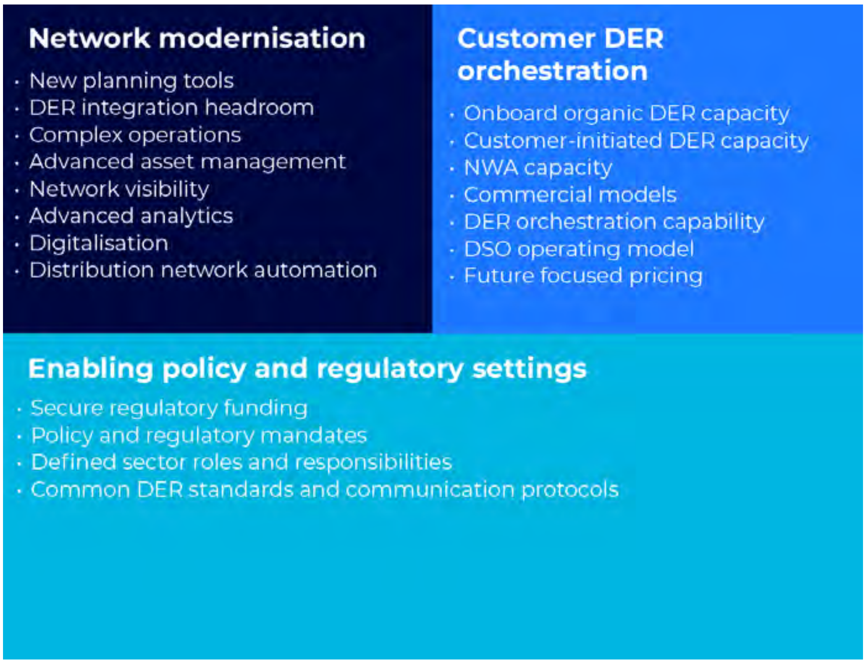


FIGURE 14-1: FUTURE NETWORK ROADMAP PATHWAYS

MANAGING COMPLEX OPERATIONS

As distribution technology advances, core traditional Operational Technology (OT) devices are becoming more and more digitally dependant in nature. This can be due to increased connectivity of assets and devices, increased data collection, increased security needs (or requirements), or device management at scale. These changes are causing significant convergence between OT and Digital spaces and devices.

Based on these advances, it is important that Vector more acutely accounts for this as scope and complexity of operating the network itself increases. Further non-network asset investment is required to ensure new processes and technologies are effectively and efficiently introduced and onboarded into Vector's operating systems. Non-network asset investment is required to:

- Secure and manage a greater volume and type of network devices,
- Efficiently operate the network with greater fidelity

- Incorporate increasing data into processes and tools from an increasing number of 3rd party sources
- Increasingly allow both Vector and 3rd party support entities to secure and seamless access to relevant systems and data
- Introduce and provision management of the LV network

NETWORK MODERNISATION

There are a number of factors which are driving a category of planning we have termed Network Modernisation. Traditional network growth, changing customer behaviours and requirements, alongside technology advances all mean Vector expects to see a significant increase in both traditional and non-traditional/new asset types forming part of the network. In order to effectively plan for this increasingly variable future state, dynamic planning tools must be developed and utilised, in order to help better optimise for capacity, cost, resilience and reliability. As new asset types (or devices that may connect to the network) are introduced, we need to be able to understand their impact quickly and efficiently, or to provide potential customers with toolsets in order guide their planning. We must leverage both existing and new datasets to gain new and better insights, in order to optimise asset lifecycles and ensure our capital investment is directed in the most effective way. Significant progress is underway in this area as a result of Vector's partnership with X (formerly Google X), where we are undertaking innovation and development activities relating to the development of a platform which facilitates the virtualisation and simulation across Vector's network, with a focus on expedient options analysis and ease of updating asset types and properties.

NETWORK VISIBILITY

A key element of supporting the asset strategy is providing a complete and accurate view of the Network from as as-built and as-operated perspectives, in close to real-time. This will involve an uptake in data utilisation from pre-existing sources. Additionally, the growth in both network size and scope will require experimentation with new data sources from both the field and a significant number of external partners. This change will be particularly pronounced in the LV network as changing customer needs and the impact of DERs will require this visibility to be extended to the meter.

DERS

The increasing prevalence of DERs on the network mean specific focus is required in this area, notwithstanding the management and utilisation of DERs being integral to the non-network solution aspect of Vector's Symphony Strategy. The proliferation of DERs will drive changes in customer demands, increased commercial engagements, and the potential for new pricing and planning strategies. Vector systems will need to be updated and kept current to accommodate these changes prior to the real-world implementation, in order to appropriately enable smooth and effective DER integration into the Vector environment.

DIGITALISATION

Investment is required across Vector's corporate systems to accommodate the predicted changes in terms of scale. This can span the number of active devices, volume of data required to be processed and stored, number of employees or number of partners. Subsequent implications for training, onboarding, health and safety are additional examples where digitalisation is needed to keep pace with our projected rate of growth.

INSIGHTS & DATA MANAGEMENT

In order to keep pace with the increasing change on the horizon, a platform investment is needed in both the underlying data platform, governance and analytics capabilities. This platform will need to be able to handle the increased scale requirements resulting from both a bigger network but also the increased data from a smarter one.

APPROACH TO INVESTMENT HORIZONS

To this end, we have developed a plan with a higher degree of certainty for the first two to three years, and less specificity thereafter. In the latter years, we have less fidelity over exact projects but have proportionally projected investment levels in each of the Value Streams (key areas that define and manage the digital execution of components that make up our Electricity Distribution Business). Given the rate of change in technology, we continuously look for the optimal solution, whether this is through the use of new and emerging digital technologies or optimising existing solutions. This section is structured to reflect this, and comprised of two parts:

1. Strategic areas of focus resulting in significant projects and programme investments
2. Value Stream Need Statements outlining desired investment outcomes

For all the projects described below we looked for the optimal solution before deciding on the investment choice (and will continue to do so). Whether this is through the use of new and emerging digital technologies, or existing solutions, in all cases, we identify the solution that will deliver the best outcome for our customers.

14.4 Significant projects / programmes of work - Networks Digital

14.4.1 MANAGING COMPLEX OPERATIONS

14.4.1.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS): IMPLEMENTATION OF PHASE- II

Vector is focused on investing in platforms that support and improve core network operations. One of the key investments in this area is an Advanced Distribution Management System (ADMS). The core component of an ADMS, the SCADA platform, has been replaced and integrated as part of our ADMS Phase-I initiative, scheduled to be completed at the end of RY23.

This phase is focused on making sure that the data available to and generated in the field and control room needs to be provided in near real-time to corporate and customer systems. This will allow operators to operate the network without the need for manual processing to keep customer and business stakeholders aware and informed as to the state of the network. These changes will allow the control room to see calls coming from customers as they relate to specific network assets.

ADMS PHASE -II

Investment now focuses on Phase-II of this programme – establishing and integrating OMS and SOM:

- Outage Management System (OMS) – this functionality will predict the most likely fault location and provide relevant information to control room operators, to minimise response times.
- Switch Order Management (SOM) – this functionality will allow the reduction of reactive switching times through the use of what-if scenario tools and automatic safety checking. Longer term, this functionality will be used to fully autogenerate restoration switching sequences, freeing up operators to concentrate on other operational tasks.

There are several drivers and benefits to investing in an ADMS:

1. **Customer Experience**: Customers will receive reliable information regarding outages through better system integration, **automated** processes and improved data capture and validation.
2. **Safety**: Reduced risk of human error to prevent harm to people and assets through digitisation and automation of error prone manual processes
3. **Resilience**: Improved SAIDI performance through faster outage response and restoration times - including major event recovery, enabled by:

- Efficient utilisation of smart assets in the field using automated fault identification and restoration sequences.
- Supported decision making and better situational awareness in the EOC through integrated tools and automated processes.
- Increased focus on network operations by controllers through intelligent systems and system visibility drawing attention to critical issues.
- Improved prioritisation of fault restoration through real-time fault location information and crew visibility and utilisation.

4. **Reliability**: Improved SAIFI performance through use of smart field equipment via automation processes supported by enhanced asset management practices providing rich data capture.
5. **Cyber Security**: Reduced risk of cyber-attacks resulting from Operational Technology (OT) and Information Technology (IT) network convergence through utilising security by design principles enabled by a modern ADMS ecosystem.

An ADMS creates an ecosystem where DERMS combined with Outage Management and real time LV Visibility, will allow us to be able to provide better outage planning utilising DERs as well as managing peaks with DER support, thus ensuring optimal investment from traditional assets.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
ADMS Phase II	7.5	6.0									13.5

TABLE 14-2: ADMS PHASE II INVESMENT FORECAST

14.4.1.2 OPERATIONAL TECHNOLOGY (OT) CYBER SECUIRTY

The global Cyber Security landscape is changing and with it Vector's investment needs to continue to build cyber resilience, stay current and build new capability to stay ahead of the various threats acts globally. There are several macro trends that are driving Vector's need for significant investment in the OT cyber security zone including the increasing number of devices, more telemetered devices needing to be deployed on poles and a greater number of sites.

Operational information is increasingly needing to be combined with data from the field in order to enable optimal decision making in the control room. An ever-increasing scope and capability of devices coming from vendors provides opportunity to increase visibility and control however it may also increase our level of potential vulnerabilities. Supply chain vulnerabilities pose an increasing risk resulting from various geopolitical changes. And the potential for a greater capability and willingness to execute against T1 infrastructure from advanced threat actors worldwide remains a pervasive risk.

These trends mean that the reliance on 'air gapping' and network level controls for security in an OT environment is no longer sufficient to keep pace. Investment needs to be made in the following technologies for anomaly detection, end point protection, device management and remote access to protect the OT Network and continuity of supply.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
OT Cyber Security	0.4	0.3	0.5	2.3	1.45	0.45	1.25	0.25	0.25	0.25	7.4

TABLE 14-3: OT CYBER SECURITY INVESTMENT FORECAST14.4.1.3 LV AND DER OPERATIONS

At the conclusion of ADMS phase II and the ADMS program Vector will begin its LV/DER ops programme. This programme of work will focus on leveraging the existing ADMS system to incorporate LV and DER information from the corporate environment, and making the interface and processes within the control room scale with our approach to managing LV.

There are a number of investment horizons which correspond to the depth to which we will manage LV and DER flexibility. Investment Phases are expected to be as follows:

- Phase I - (RY26-27) Vector LV visibility to support Outage management and critical decision-making processes. At this time, we will be continuing to expand our DERs large partner integrations and improve visibility for the control room
- Phase II - (RY30) Investment to support LV and build DER operations management
- Phase III - (RY31-33) The tail of the investment is to support the large operational system changes at scale.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
LV and DERs			2.5	2.5			1.25		1.5	1.0	8.75

TABLE 14-4: LV AND DER OPERATIONS INVESTMENT FORECAST

14.4.2 NETWORK MODERNISATION

14.4.2.1 PLANNING TOOLS

In an increasingly complex and evolving environment, there is a need for a more sophisticated network planning toolset enabling a more dynamic approach. The toolset needs to deliver the capability to rapidly explore multiple investment options and optimise on key parameters to drive the desired outcomes with improved capital efficiency. An iterative and rapid exploration approach has the potential to transform the AMP process and further optimise vector's investment planning.

As outlined in Section 10.4, Vector is in partnership with X (formerly Google X) to develop Grid Planning Tool as part of the Tapestry Platform - a platform that virtualises the network, allowing for complex simulations that can then be leveraged to rapidly test and evolve investment options to achieve the desired outcomes. The platform is a significant leap in that it brings together many disparate datasets and allows Network Planners to leverage more holistic data driven solutions.

Development of Grid Planning Tool will create a primary tool that Vector's Network Planners will use to identify constraints and explore and decide on the investments going into the AMP. The simulation capability will also be leveraged by the Network Operations team to explore options that allow maintenance work to occur with the least impact on customers and manage the load on the network.

The network of the future will be affected by trends in the market in and quicker and quicker manner. Whether due to the demand side increased customer uptake of technologies like EVs and edge generation, or improvements to distribution network technologies themselves, planning will need to become more dynamic on a quicker cadence. Vector has identified the need for investment in a system that will allow it quickly change assumptions in its models and base assumptions and see how they would flow and affect the network over the long term. This requirement for this is fast approaching and Vector's systems cannot continue to merely cater for the cadence of legacy demands.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Dynamic Planning Tools	1.0	0.75	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.75

TABLE 14-5: PLANNING TOOL INVESTMENT FORECAST14.4.2.2 DERMS MODERNISATION

The New Zealand DER market landscape is still beginning to emerge and there are still many factors to settle before concrete decisions can be made about how to plan and operate sufficient flexibility to meet the targets in this approach. This uncertainty in market force means that Vector sees two significant investment horizons from a systems perspective, that view has been informed and reinforced through Vector behavioural trials and Symphony modelling:

In the short term the focus is planning and demonstration. Vector's existing DERMs systems, data platforms and analytics capabilities within the organisation will need investment to be able to create trials, test predictions and adequately plan over the long term. These systems will need to be flexible and capable of working with large numbers of partners in order to support and service the landscape as the market and regulatory settings settle. Section 2 describes our goal of having 25 MW of peak load under management by at least 2027. Beyond this, over the next seven to 10 years, and once the landscape and market have settled, we anticipate the dramatic increase in number and types of devices being managed across our network. This will mean a significant investment towards the end of the period in order to scale and make operational a modern DER orchestration platform capable of interacting both directly with some devices, and with the parties controlling the others.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
DERMs Modernisation	0.1	0.15	0.05	0.05	0.05	0.05	0.05	3.35	3.0	3.0	9.95

TABLE 14-6: DERMS MODERNISATION INVESTMENT FORECAST

14.4.3 NETWORK VISIBILITY

14.4.3.1 SMART METER DATA PROGRAMME

Vector has decided to develop the use of Smart Meter Data (SMD) in order to provide visibility of the LV network to enable a "single pane of glass" for Network Operations to manage the entire network. LV visibility is integral to Vector's Symphony Strategy to manage the future trends of decarbonisation, electrification of transport and climate change alongside the affordability, integrity, safety, and reliability of its electricity network. SMD is a key enabler of many of the initiatives on the Future Network Roadmap.

Following the first year of the programme, the proposed approach is to deliver the programme in three phases with their own strategic focus, deliverables, and associated business case. In summary the three phases are:

- Phase I (FY21-23) – Establish foundation, gain access to data, discovery & trial, minimise spend (complete)
- Phase II (FY23-25)- Scale data for whole of network view. Make the data outputs (consumption, device data, power quality) available to be operationalised in other Vector Electricity systems to drive more timely and effective decision making
- Phase III (FY26-30) – Establish near-real-time data availability across Vector system landscape as we move towards increased automation

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Smart Meter and Data Use Cases	0.75	0.55	0.25	0.25	0.25	0.25	0.25	0.25	025	0.25	3.3

TABLE 14-7: SMART METER & DATA USE CASES INVESTMENT FORECAST

14.4.3.2 GIS ELECTRONIC AS-BUILTING

Currently, when changes to the network are done in the field, technicians are required to manually record changes and then records are digitally recorded in the office after the fact. This results in latency in updating information as well as increased costs and overheads. Vector will focus on capturing these changes digitally in the field as they happen. This will be the final piece of connecting or As-Designed to As-Built to As-Operated model. Keeping these models will allow Vector decision makers access to more timely and accurate information. Additionally, Vector will be able to provide customers more accurate outage information as they will be aware of changes in the Network on a daily rather than monthly cadence.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
GIS -Electronic As-Builting			3.0								3.0

TABLE 14-8: ELECRTRONIC AS-BUILT INVESTMENT FORECAST

14.5 Insights and data management

14.5.1 DATA WAREHOUSE MODERNISATION

As Vector continues to ingest data from a greater number of sources our underlying platform will need significant investment. This platform will need to be able to store and process an order of magnitude more data that previously required. Additionally, much data will come will limitations on who and for what purpose the data can be consumed. These constraints must follow the data as it progresses through to data analytics and systems of record. This will require a step change in our data warehousing capability. Vector is pursuing an implementation of the Snowflake platform. This will allow Vector to maintain its governance requirements whilst simultaneously enabling the scale and performance need to maintain other initiatives. This requires an initial investment to support planning and build requirements and then subsequent investment later in the period in order to be ready to meet the scale demands of the operational requirements.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Data Warehouse Modernisation	0.5	0.5	0.2			0.1	0.9	0.1	0.1	0.1	2.5

TABLE 14-9: DATA WAREHOUSE MODERNISATION INVESTEMENT FORECAST

14.6 Significant projects / programmes of work – Vector Group and Core Digital

The following areas have been identified as requiring capital investment over the course of the planning period, with relevant commentary around their development, maintenance and/or renewal detailed below. All investment is in line with Vector's asset replacement lifecycle processes. Other minor systems are expected to require replacement or upgrade during the planning period however their cost is not material in terms of the non-network investment forecast.

14.6.1 IT NETWORK MODERNISATION

The Vector group, like most modern organisations, relies heavily on reliable, consistent, and secure access to the internet to conduct its day-to-day operations. This is required across all devices and all office locations, with both wired and wireless connectivity a baseline expectation of employees, team members and stakeholders across the organisation. As more services continue to move to the cloud, there is an increasing need to modernise the IT network to reduce functional issues and manage security risks. This is a critical and ongoing work as the IT network is foundational to all system technologies.

The Vector Group IT Network Modernisation project includes both, the corporate IT and elements of the Electricity OT (Operational Technology) Ethernet computer networks. The functional role of these networks is to provide secure and reliable access to the internet, and effectively limit access to some areas of the network to provide redundancy and disaster recovery capability, alongside enabling the transfer of data from machine to machine both internally, and where appropriate, outside of the Vector network e.g. for Field Service Providers. Connectivity is a critical component of effectively managing and maintaining our core Network and Business operations, as losing connectivity, or having insecure access to the internet would directly impact our visibility of core network alarms and prevent us from effectively providing any services to our customers, stakeholders or businesses who rely on that connectivity.

Over the last two years significant improvements have been made in this space particularly in the replacement of all the OT Firewalls and modernisation of current network services. This area of investment continues with the next phases focusing on Network segmentation and the scaling our investment in anomaly detection and perimeter vulnerability management.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
IT Network Modernisation	2.3	1.2	0.4	0.4	0.3	0.2	2.2	0.4	0.4	0.4	8.2

TABLE 14-10: IT NETWORK MODERNISATION INVESTMENT FORECAST

14.6.2 ERP MODERNISATION - SAP UPGRADE

Vector uses SAP for several critical functions; from it being our financial system of record to being used for core asset management, material management, project systems, sales and distribution and HR. In recent years this system has become central to the electricity business in that it receives all the maintenance records from our field service providers. This has provided us with greater visibility over asset health and has enabled us to be more proactive in our asset management capabilities.

Vector's SAP implementation is running ECC. Although Vector has kept ECC patched and running up to date, the product is approaching end of life. An upgrade is a significant undertaking which will require multiple years for execution. Vector is likely to upgrade from EC to S4 / HANA by 2027.

This upgrade needs to be made in a manner to allow Vector to pursue a conditional based model for Asset Management across a significantly expanding number of assets. The demand in scale is driven not just by an expansion of network capacity but also by the number of new assets that will need to be tracked in order to meet the needs of network visibility. ERP (Enterprise Resource Planning) modernisation and transformation will enable automation and scalability of the Risk Based Approach described in Section 8.5.2.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
ERP Transformation	0.7	3.6	5.0	5.0							14.3

TABLE 14-11: SAP UPGRADE INVESTMENT FORECAST

14.6.3 CLOUD MIGRATION

With the rapid evolution of cloud services, and the inherent advantages of automated scaling, reduced operational cost and significantly improved resilience and recovery, there is an ongoing need to move towards cloud-based infrastructure.

Cloud technologies directly support the achievement of our Asset Management Objectives through improved capability (e.g. for data storage and backup), enable enhanced data analytics and simplify the digital technology infrastructure at a more efficient cost.

More importantly, the migration of applications and infrastructure to cloud first technologies also provides enhanced capabilities to capture and consume the increasing amount of data that is being generated and used across the network, and then better utilise this data in near real time to make accurate, relevant and timely decisions. Increasing penetration of DERs, investments in technology at the grid edge, increasing scale of microgrid deployments, distributed control of network assets all require significant connectivity with an associated demand on computing power – cloud first technologies provide this computing power at scale at a significantly lower cost per unit than on-premise and datacentre infrastructure.

Investment in cloud migration continues alongside the move of our Data Centre move and is core it it's timely completion.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Cloud Migration	0.43	0.43									0.86

TABLE 14-12: CLOUD MIGRATION INVESTMENT FORECAST

14.6.4 DATA CENTRE TRANSFORMATION

Vector is vacating its premises in CGR101 and moving to a new building, CGR110, which requires networking & AV. Leaving CGR101 means that we must relocate our primary datacentre, which is provides critical services to Electricity, Fibre and Corporate operations. The need to vacate the current premise provides an opportunity to modernise what was a 30yr old datacentre, improve Disaster Recovery capability and the remediation of technical debt that exists in such an aged facility.

The key outcomes, based on future proofing the user experience through new technology, to be addressed by this programme are as follows:

- CGR101 DC evacuation and migration by Oct 2024 to a new facility that is highly resilient and managed
- Address and simplify the amalgamation of services by following good architecture practices and documenting the as-built state
- Address operational risk by building a disaster recovery capability with a documented failover plan for the services which require DR

- Repurpose existing hardware in warranty & acquire minimal new equipment to ensure a sustainable asset lifecycle exists for all services and longevity of rebuild investment
- Migrate services to the cloud as a 'cloud first' principle to reduce the burden of maintaining physical infrastructure & mitigate hardware out of warranty

This program will be supported by the cloud migration and infrastructure lifecycle management work also underway.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Datacentre Transformation	4.3	2.5									6.8

TABLE 14-13: DATACENTRE TRANSFORMATION INVESTMENT FORECAST

14.6.5 IT INFRASTRUCTURE LIFECYCLE MANAGEMENT

Vector operates significant and complex compute, network and storage infrastructure and architectures across both Information Technology (IT) and Operational Technology (OT) environments. These environments require significant ongoing investment to maintain infrastructure at vendor supported levels to meet best practice performance and security requirements.

Vector is continuously developing refreshed compute, network and storage operating model and capabilities which will support the Group, Business and Digital operations to achieve Vector's strategy and vision. All investment in this area is aligned with each asset's lifecycle. Effective lifecycle management of digital assets improves Vector's ability to its Asset Management Objectives.

Within the IT infrastructure lifecycle management program there is a focus on continuous improvement and not creating technical debt, these principles are enabled by clear business strategies and supported by 24 month rolling roadmaps that allow Vector Digital to make the right infrastructure investment decisions to support Vectors need to scale and automate as effectively as possible.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
IT Infrastructure Lifecycle Mgmt.	1.3	1.3	1.6	1.6	1.6	1.6	1.6	1.4	1.4	1.4	14.9

Table 14-14: IT INFRASTRUCURE LIFECYCLE MANAGEMENT INVESTMENT FORECAST

14.7 Value Stream needs statements – Networks Digital

Please note the Value Stream investment breakdowns below include the projects detailed above.

14.7.1 CUSTOMER OPERATIONS

The Customer Operations Value Stream sole focus is to ensure that customers have a great experience whenever they engage with Vector. The investment is focused on new capabilities to serve customers increased and changing needs, alongside continuous improvement based on customer feedback. All projects in this value stream include customer research and customer testing to ensure that the solutions we provide to customers are fit for purpose and deliver a great experience.

Vector continues to invest in designing experiences that allow for richer and more informative interactions during outages. Development of Vector's Outage Centre has allowed customers to directly and more easily interact with Vector to report outages and receive ongoing information on the progress of resolving outages. Additionally, customers are able to get information on planned outages so they can plan and minimise the impact to their lives.

Vector continues to invest in improving the Outage Centre experience while transitioning to a strong focus on self-service for customers. This shift is driven by the customers' desire for customers to have more channel choice and control as they take on and manage products and services from Vector. Self-service platforms also form the foundation for the scalability which will be required to cater for the increased types and volumes of interactions that we anticipate over time.

Specific projects included in this investment category include continuous improvements in Vector's Outage Centre based on customer feedback, self-service for customers with an initial focus on connections, disconnections, and alterations, alongside continued investment in new and existing customer channels for support, for example via webchat and pro-active SMS notifications. Further, the expected investment in foundational capability required over time is reflected in the outer years, where there is recognition that as customers' requirements to change, Vector's service mix must also evolve to meet them. Based on this. there are allowances for both back-office systems and front end development aimed at catering for and responding to changing customer behaviour, as well as enabling Vector to undertake demand response type activity with direct customer engagement.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Customer Operations	1.8	1.8	2.9	4.8	4.9	2.0	1.4	2.0	1.4	1.4	24.1

TABLE 14-15: CUSTOMER OPERATIONS INVESTMENT FORECAST

14.7.2 NETWORK OPERATIONS

Network operations investment is targeted at ensuring we operate a consistent, reliable, and resilient supply across the network, and the digital capabilities required to support the achievement of this. The network operations domain includes multiple categories and functions which are required to support the execution and management of a distribution network in the future.

The focus of this investment category in the early years of the period is on development of fit for purpose capability to enable enhanced control room functions, with increasing capability in operational management of outage events across their lifecycle, including significant events. In parallel, there is capability growth associated with meeting the changing customer expectations for electricity, including increased EV and smart device penetration. Examples of specific initiatives categorised here include fault location detection, weather monitoring and the potential impact on the network, further ADMS enhancements such as mobile field switching, etc.

Scalability across all functions of Network Operations is once again key to ensuring our both our Asset Management Objectives (and in particular, the Future Energy Network aspect) are achieved. As the number of assets on the network grows, alongside customer connections, proliferation of DERs, the opportunity for more active management of the LV network, all the while meeting the expectations of customers, means managing complex operations becomes a core tenet of our investment roadmap.

As we move to the second phase of our ADMS implementation (with Phase 1 – replacement of SCADA - being completed in RY23), investment now focuses on implementation of OMS and SOM, and integrating these processes in order to achieve operational efficiency and enhanced customer experience.

Further to managing complex operations, inhouse capability to assist in delivering effective and efficient field services is critical to improving capability to meet customer needs. In line with this there is investment and initiatives covering aspects such as permit management, scheduling and notification of planned works, field crew loading analysis and work order scheduling.

The Network Operations digital investment category targets both specific projects and expected investment in required capabilities to enable enhanced network performance, and ensures that we deliver effective, resilient and reliable services.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Network Operations	11.7	10.7	13.4	11.1	6.0	8.4	7.0	4.1	6.7	12.2	91.1

TABLE 14-16: NETWORK OPERATIONS INVESTMENT FORECAST

14.7.3 NETWORK CONTRUCTION & DESIGN

Network Construction and Design investment is targeted at ensuring consistent and reliable ways of running network projects (e.g. growth and asset replacement). The digital capabilities required to support achievement of this are, a state-of-the-art portfolio management system, drawing management system and associated processes. Based on the required capital investment for network build, a particular focus of this Value Stream is optimising Inventory Management processes, in order to enhance and maximise efficiency when executing capital projects. The network construction and design domain includes multiple categories and functions which are required to support the execution and management of a growing and enhancing Vector's distribution network in the future.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Construction and Design	0.2	0.4	0.2	0.2	1.7	1.6	0.5	0.2	0.2	0.2	5.3

TABLE 14-17: NETWORK CONSTRUCTION AND DESIGN INVESTMENT FORECAST

14.7.4 MAINTENANCE & ASSET MANAGEMENT

The key drivers in this stream are to get better visibility of maintenance activities and their results, to improve asset management capabilities around total cost of ownership (TCO) and Asset Risk Management. As outlined in Section 14.7.2 SAP-PM has become central to the electricity business in that it receives all the maintenance records from our field service providers, providing significantly greater visibility over asset health, and has enabled us to be more proactive in our asset management capabilities.

Condition Based Asset Risk Management (CBARM), Condition Based Maintenance (CBM) and Fault Prediction are key foci of this value stream. Further work is required in these areas, to both continue to grow the capability and effectiveness, as well as ensuring they are scalable, particularly when adding a greater number of assets, and especially more complex assets.

The investment strategy for these key systems will be anchored in further developing the plant maintenance module of SAP (SAP-PM) alongside the upgrade of this platform. The benefits of this include providing operational history, allowing planned and corrective maintenance activities to be monitored and updated, incorporating a record of financial costs and equipping FSPs with access to a fully mobile information system at each work site. With the foundational improvements made to standardise asset information completed, Vector continues to leverage new technologies making it more efficient to collect asset information, plan maintenance work and further optimise the execution of maintenance work to reduce outages.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Maintenance and Asset Mgmt.	1.1	0.4	1.9	2.3	0.75	0.7	0.6	0.85	0.55	0.8	9.95

TABLE 14-18: MAINTENANCE AND ASSET MANAGEMENT INVESTMENT FORECAST

14.7.5 RECORDS AND INFORMATION MANAGEMENT

Records and Information Management Value Stream ensures that decision makers across the business have easy access to well structured, integrated and high-quality data to optimise operational processes, ensure regulatory compliance and support more advanced analytics capabilities.

The focus of investment has been on ensuring primary network information systems and data sets are in place to support fundamental network processes, and a single version or systems of records. In addition, the focus is on improved tools and data sources for data exploration and use and laying foundations for the requisite administration and management of data required for both core business data systems and LV network data management. Example of this are Asset management systems integration, BI platform enhancements for SAIDI and SAIFI tracking and DDA data management.

Previous years' work has seen significant progress on the acquisition and processing of Smart Meter Data sets – a key enabling component across the Value Stream, but also outcomes embedded within other Value Streams (e.g. Network Operations, Customer Operations and Network Planning). Investment in the near term is focussed on operationalising these datasets and realising value from the initial use-cases, alongside the mid-term of enhancing planning and operations by helping facilitate LV Visibility.

We have developed in-house capabilities to support strong information management practices across the business, and these include a team for data quality management, development of data standards, and data governance.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Records and Information Management	4.1	2.85	6.4	3.1	1.75	2.8	2.55	2.6	3.55	2.5	32.2

TABLE 14-19: RECORDS AND INFORMATION MANAGEMENT INVESTMENT FORECAST

14.7.6 NETWORK PLANNING

Network Planning investment is targeted at ensuring consistent, reliable, and resilient supply across the network, and the digital capabilities required to support achievement of this. The network planning domain includes multiple categories and functions which are required to support the planning, execution and management of a distribution network in the future.

The focus of this investment category in the early years of the period is on enhancing Vector's symphony modelling capability to better understand the impact of DERs on the network, alongside initial targeted DER Management applications. In parallel, there is capability growth associated with meeting the changing customer expectations for electricity, including increased EV and smart device penetration and how customers can play a more active role in the electricity value chain.

The ability to perform Dynamic Planning forms a key pillar of achieving our Asset Management Objectives, and Symphony goals. Vector continues in a partnership with X (Google X) to develop a platform which looks to facilitate virtualisation, simulation and orchestration across the network using both existing and new datasets, leveraging bleeding edge technology – in particular across AI and ML capabilities – to assist in performing expedient analysis based on changing inputs, provide a greater breadth of options analysis.

We are also working to improve our understanding of LV network performance (LV visibility). To achieve these outcomes, Vector will put a focus on:

- Increased network monitoring to enable real-time modelling. Successful implementation may lead to the use of dynamic ratings to increase network utilisation without breaching equipment ratings, alongside new simulation capability. This is ultimately both a planning and operations tool.
- Improvements and simplification of the method to calculate the spare capacity on the distribution network to enable more efficient use of the network distribution assets and ultimately capex investment.
- Implementing a platform for managing those field devices that need to be managed, for both energy injection (e.g. solar/PV, batteries) and energy offset devices (e.g. HWLC, smart charging and implementation of Dynamic Operating Envelopes for specific customers).
- Increased demand and voltage monitoring capability of the LV network. Current practices of installing short-term dataloggers is inadequate as it still requires an estimate of peak demand. 24/7 monitoring is required together with efficient data management.

The Network Planning digital investment category targets both specific projects and expected investment in required capabilities to enable enhanced network performance and ensures that we deliver effective and resilient services.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Network Planning	2.7	1.5	1.3	1.4	1.0	1.0	1.0	4.3	4.0	4.0	22.2

TABLE 14-30: NETWORK PLANNING INVESTMENT FORECAST

14.8 Value Stream needs statements – Core Digital

14.8.1 CORPORATE

The Corporate Value Stream ensures that the appropriate systems and tools are in place for the corporate functions of Vector to function effectively. Investments are focused to establish and support tools for functions such as Finance, Regulatory, Marketing and Communications, Legal and Risk.

The most significant area of Investment in the upcoming years is the modernisation of Vector ERP system, as documented above. Other areas of focus continue to be payroll, document management and customer communication tools.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Corporate	1.9	4.1	6.7	7.4	2.2	2.2	1.4	1.2	1.8	0.7	29.6

TABLE 14-41: CORPORATE INVESTMENT FORECAST

14.8.2 EMPLOYEE EXPERIENCE

The Employee Experience Value Stream focuses on two main areas, ensuring that Vector employees are equipped and mobilised to fully engage and perform their roles effectively and the lifecycle of an employee at Vector from Onboarding, to learning, leadership, performance management, employee engagement and offboarding This includes having the appropriate devices, connectivity, IT support that allows for independent and collaborative work, along with the supporting mechanisms that encourage an engaged workforce.

With the need for increased flexible working scenarios there continues to be investment in Digital tools to support collaboration and dispersed workforces with a focus on security and user experience We continue to operate in a tight labour market and need to attract and retain talent, this means we are focusing investment in the area of automation of the lifecycle of an employee and staff learning and engagement.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Employee Experience	2.4	2.5	2.5	2.5	2.7	2.7	2.8	2.7	2.8	2.3	25.8

TABLE 14-52: EMPLOYEE EXPERIENCE INVESTMENT FORECAST

14.8.3 DIGITAL SERVICES PROVIDER

The focus for this portfolio of Value Streams is to drive better efficiency and effectiveness by establishing consistent digital toolsets and core platform components that all digital solutions can leverage. The outputs are consumed by all Value Streams thus avoiding duplication and the standardisation leads to more efficiency in the operation and support of our Digital ecosystem.

There are three Value Streams within this portfolio:

- Shared Tools and Services: Manage and operationalize standardized digital tools
- Site Reliability: Provide Value Streams with the ability to build and operate scalable and highly reliable digital solutions
- Networking and Security: Provide a secure and scalable IT network to protect against cyber security threats.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Digital Services	8.7	5.8	2.5	2.2	2.1	2.1	4.7	2.2	2.2	2.1	34.6

TABLE 14-23: DIGITAL SERVICES PROVIDER

14.9 Non-network property

Non-network Property and Leases CAPEX provides accommodation required to ensure the network business can operate as an effective, well-governed business. The networks business benefits from economies of scale with Vector providing shared accommodation across its group of regulated and non-regulated businesses. In addition to accommodation these values reflect warehousing arrangements and Right of Use (ROU) lease assets specific to the Networks business.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
Non-network Property and Leases	21.1	2.5	5.9	1.2	5.1	3.1	1.3	8.0	4.0	4.3	56.5

TABLE 14-64: NON-NETWORK PROPERTY INVESTMENT FORECAST

14.10 Non-network OPEX

Total non-network OPEX is projected to be $1,176 million over the 10-year AMP planning period.

- Expenditure on System Operations and Network support is forecasted to be $625 million for the period FY24-FY33. This expenditure line item captures direct system and network support costs that are required to deliver on the capex and maintenance plans.
- The above expenditure also includes a share of expenditure related to the resource shared between Vector's Electricity and Gas Distribution businesses.
- Business Support expenditure is forecasted to be $551 million over the AMP planning period. Business Support expenditure includes a share of health and safety, public policy & regulatory, legal & risk management, finance, human resources, digital and marketing costs incurred at Vector Group level. The Electricity Distribution business benefits from economies of scale with Vector providing shared support across its group of businesses.

DESCRIPTION	FY24 $M	FY25 $M	FY26 $M	FY27 $M	FY28 $M	FY29 $M	FY30 $M	FY31 $M	FY32 $M	FY33 $M	TOTAL $M
System operations and network support	53.8	55.7	57.9	59.7	61.3	63.1	65.4	67.4	69.4	71.6	625.4
Business Support	48.9	50.5	51.9	53.2	54.4	55.7	56.9	58.3	59.6	61.0	550.5

TABLE 14-75: NON-NETWORK OPEX (FINANCIAL YEAR, $'000 NOMINAL)

14.11 Expenditure forecast –Non-Network CAPEX

Figure 14-1 presents the total non-network CAPEX forecast expenditure for the 10-year planning period.

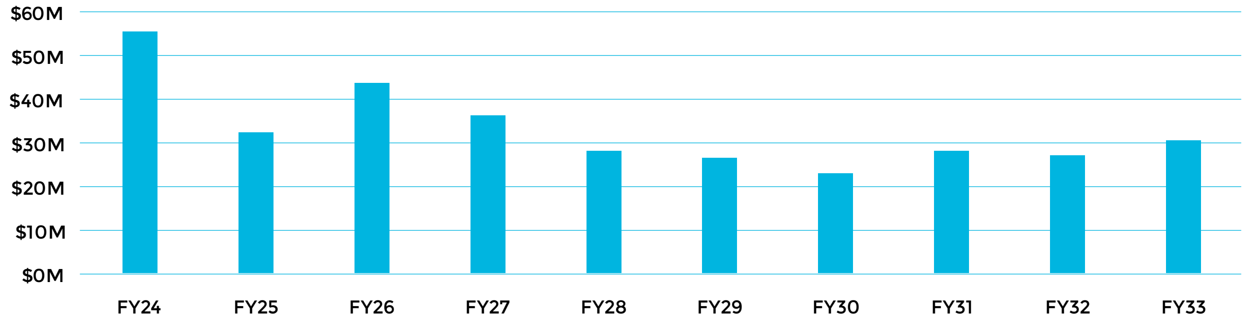


FIGURE 14-2: NON-NETWORK CAPEX

SECTION 15

Expenditure forecasts

15 –Expenditure forecast

15.1 Overview

This section describes the CAPEX and OPEX forecasts for the electricity distribution network assets for the next 10-year planning period based on the investment proposals outlined in Sections 8 to 14. It includes context for key assumptions and provides a high-level comparison with the forecast included in the 2022 AMP (disclosed in March 2022).

The CAPEX and OPEX forecasts presented in this section align with Vector's planning process and financial year (FY) reporting period 1 July to 30 June. All figures presented are in 2023 dollars. The regulatory disclosure forecast, shown in Appendix 6 and Appendix 7, are presented in regulatory year (RY) 1 April to 31 March, in both constant and nominal dollars, as per the Information Disclosure requirements.

15.2 CAPEX forecast

The forecast CAPEX during the next 10-year planning period is presented below, based on our key asset management strategies, demand modelling and customer information available. These are grouped in the following categories:

- **Growth CAPEX** – detail discussed in Sections 9, 10 and 13, and includes Customer Connection, System Growth and Relocations.
- **Integrity CAPEX** – detail discussed in Sections 11 and 12, and includes Asset Replacement and Renewal, and Reliability, Safety and Environment.
- **Non-network CAPEX** – detail discussed in Section 14.

Note all CAPEX figures shown here are gross.

15.2.1 TOTAL CAPEX

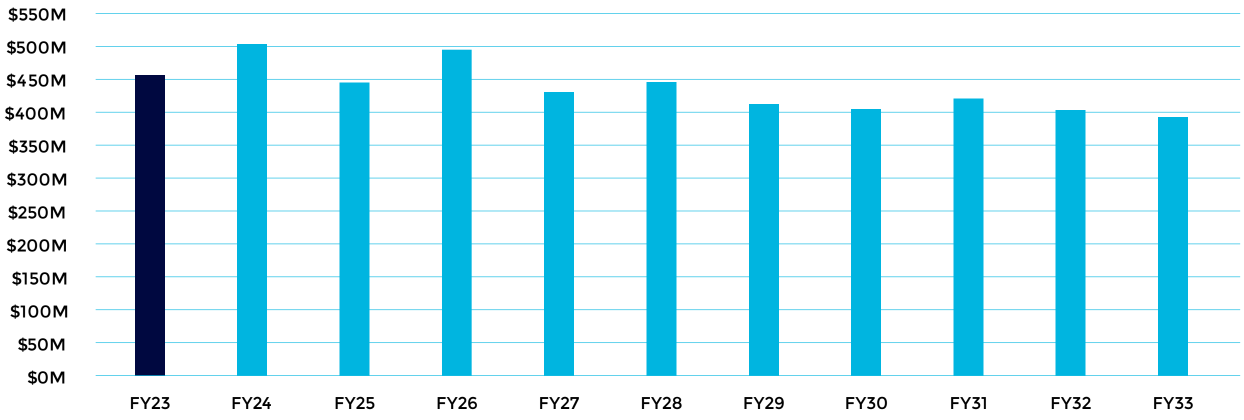


FIGURE 15.1: TOTAL CAPEX

Total CAPEX averages $439m p.a. with expenditure profile reflecting the growth and integrity forecast (see detail in the following sections), which are punctuated by large significant projects for which there is more certainty in the short term. The higher FY24 to FY26 gross expenditure is driven by increased customer connections expenditure and associated system reinforcement requirement, as well as additional network hardening initiatives commencing in FY26. The expenditure profile also aligns with network technology initiatives including ADMS Phase II implementation, data centre, cyber and platform lifecycle management initiatives.

15.2.2 GROWTH CAPEX

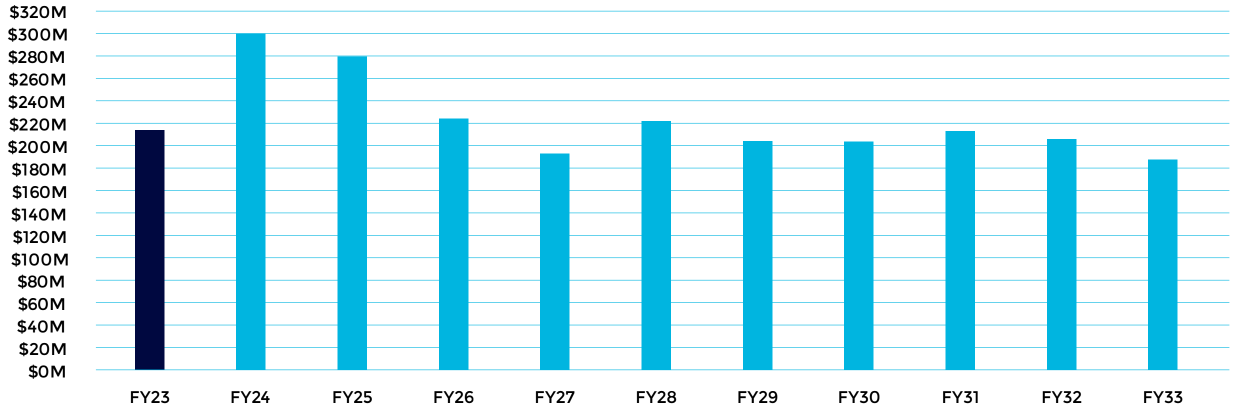


FIGURE 15.2: GROWTH CAPEX

The expenditure profile for Growth CAPEX is influenced by the timing of significant projects with large capital outlay. The higher spend in FY24 and FY25 is driven by several large customer connections and network capacity investments including six data centres, eight transport electrification projects, two new zone substations and two zone substation upgrades. During the period there are provisions for seven land purchases and continuation of the Wellsford-Warkworth subtransmision cable and duct installation.

The expenditure level from FY26 onwards averages circa $200m, increasing from an average of $168m in the previous AMP, reflecting strong load growth and associated reinforcement requirements forecast in the planning period. Over this period, six existing zone substations will require capacity upgrades and six new substations will be commissioned. No provision has been made for any network relocation or reinforcement associated with the proposed Auckland Light Rail infrastructure project due to project uncertainty.

15.2.3 INTEGRITY CAPEX

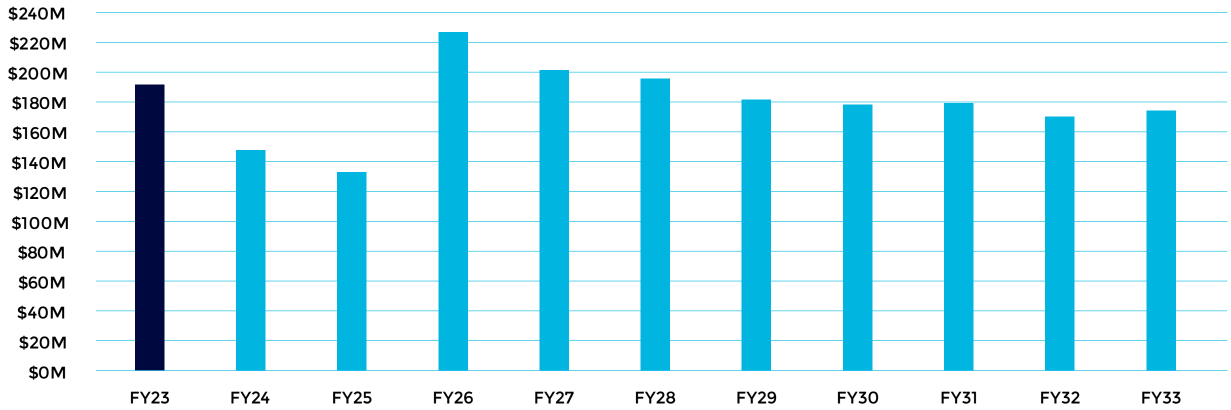


FIGURE 15.3: INTEGRITY CAPEX

The integrity expenditure is higher in FY23 and sloping down to FY25 due to projects previously planned in FY24 and FY25 being proactively brought forward to better manage the risk of project slippage resulting from supply chain delays and labour resourcing shortages that have been experienced in the last few years.

Integrity expenditure has increased from FY26 onwards to allow for a higher investment in network resilience with initiatives such as distribution overhead line hardening, sub-transmission undergrounding and relocation and elevation of zone substations. The higher FY26 forecast is also attributed to four sub-transmission cable replacement projects ($27m) that span over the financial year.

15.2.4 NON-NETWORK DIGITAL CAPEX

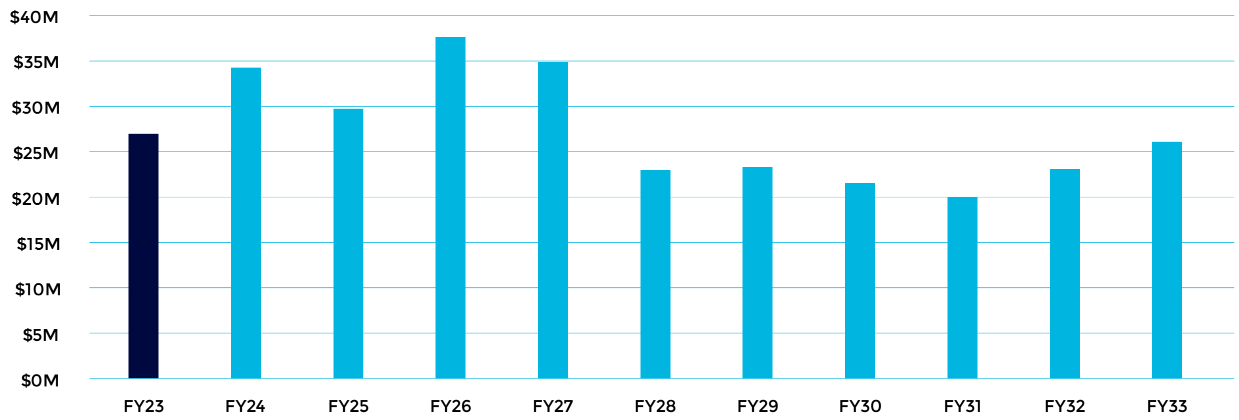


FIGURE 15.4: NON-NETWORK DIGITAL CAPEX

Digital investments support the technology required to execute our Symphony strategy. The proposed investment in the upcoming years in non-network digital systems, processes and information management will ensure Vector has the capability and tools required to deliver on our Asset Management Objectives. The focus in the near term (FY24-25) is building on the foundation delivered by the ADMS Phase I programme of work and beginning Vector's ERP (Enterprise Resource Planning) Transformation (FY24-27). The investment in ERP Transformation and Electricity growth enablement technologies will leverage modern automation and toolsets to support a scaled operation beyond 2030. Through the AMP period we continue to invest in a modernised network and lifecycle management that will both replace aged platforms and leverage new technology delivered by modernised systems.

15.2.5 NON-NETWORK PROPERTY AND LEASES

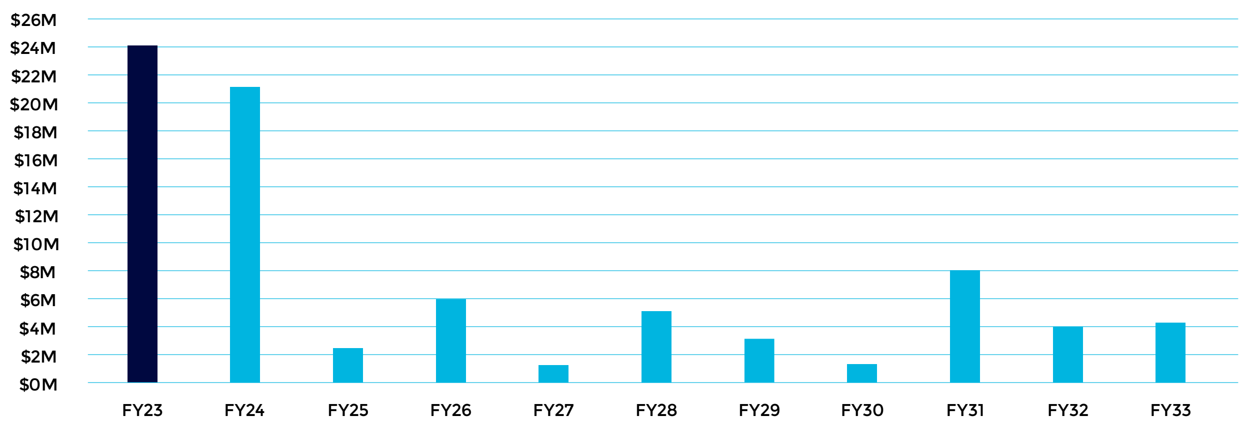


FIGURE 15.5: NON-NETWORK PROPERTY AND LEASES

Property and leases reflect risk strategies to mitigate the impact of COVID-19 with increased longer term warehousing arrangements in FY24 to mitigate supply chain risk.

Further changes to the Head Office lease drive the increase in CAPEX in FY23.

15.3 CAPEX forecast variance to previous AMP

The forecast CAPEX during the next 10-year planning period is broken down into the key asset categories defined in the Commerce Commission's Electricity Distribution Information Disclosure Amendments Determination 2012 (shown in Table 15-1).

Figure 15-6 shows the difference between the 2023 and 2022 AMP expenditure forecasts year on year, with Table 15-2 breaking down the variance by expenditure categories.

KEY CAPEX CATEGORIES	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	TOTAL (FY24-33)
Consumer connection	154,234	146,545	93,438	90,704	79,363	80,339	80,339	75,162	75,162	75,162	**950,448**
System growth	111,490	95,337	96,639	65,289	108,654	90,073	89,521	103,846	96,817	78,784	**936,450**
Asset relocations	33,732	37,114	33,756	36,400	33,400	33,400	33,400	33,400	33,400	33,400	**341,402**
Asset replacement and renewal	118,562	86,959	147,520	126,466	122,368	111,453	108,386	110,109	101,978	106,988	**1,140,788**
Reliability, safety and environment	28,931	45,523	78,923	74,531	72,923	69,632	69,306	68,822	67,789	66,942	**643,323**
Non-network assets	55,251	32,117	43,501	36,004	27,937	26,341	22,797	27,955	26,957	30,297	**329,157**
Total CAPEX	**502,201**	**443,594**	**493,777**	**429,395**	**444,645**	**411,238**	**403,750**	**419,295**	**402,102**	**391,573**	**4,341,570**

TABLE 15-1: AMP 2023 CAPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY23)

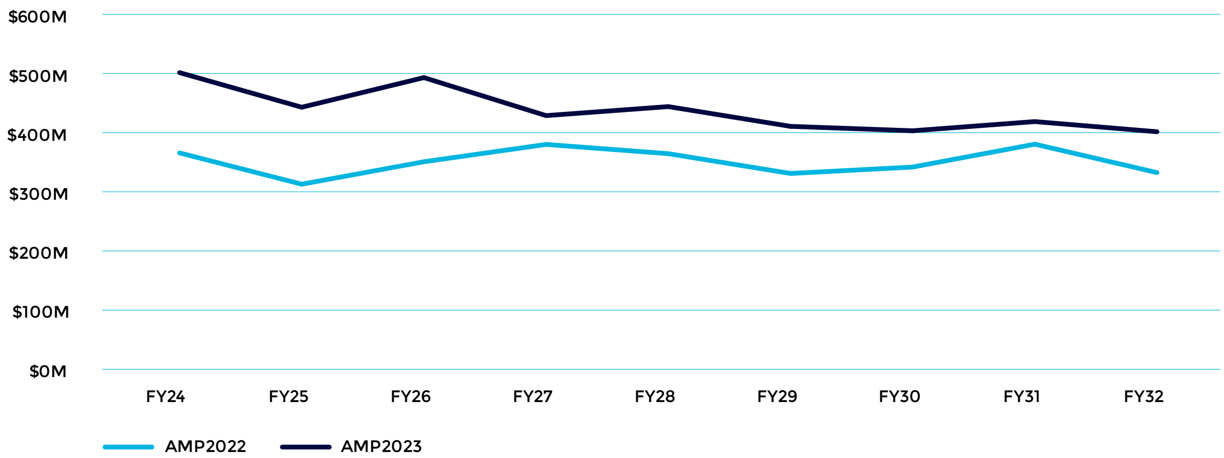


FIGURE 15.6: AMP 2023 VARIANCE TO AMP2022 CAPEX FORECAST (FINANCIAL YEAR, $M CONSTANT FY23)

KEY CAPEX CATEGORIES	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	TOTAL (FY24-32)
Consumer connection	59,544	65,655	25,906	26,393	8,224	19,064	20,269	20,460	20,460	**265,975**
System growth	56,437	55,896	41,217	(22,089)	38,459	37,889	25,973	(2,503)	22,792	**254,072**
Asset relocation	(4,095)	3,666	629	2,555	(445)	(445)	(445)	(445)	(445)	**533**
Asset replacement and renewal	15,883	(19,068)	35,444	2,095	(315)	3,929	(9,963)	(4,992)	(1,279)	**21,735**
Reliability, safety and environment	(9,017)	10,909	34,104	31,165	32,381	28,025	27,902	26,874	26,446	**208,789**
Non-network assets	17,250	13,315	5,229	8,702	1,395	(8,649)	(2,241)	(1,391)	1,242	**34,852**
Total CAPEX	**136,002**	**130,374**	**142,530**	**48,821**	**79,700**	**79,815**	**61,495**	**38,002**	**69,215**	**785,955**

TABLE 15-2: AMP 2023 VARIANCE TO AMP2022 CAPEX FORECAST TABLE (FINANCIAL YEAR, $'000 CONSTANT FY23)

15.3.1 EXPLANATION OF MAJOR NETWORK CAPEX VARIANCES

Key changes in Network CAPEX over the 9 years for which the 2022 AMP and 2023 AMP overlap are as follows:

- A significant increase in customer connection gross expenditure driven by higher large customer dedicated network investments ($162m) primarily relating to data centres ($75m) and e-transport infrastructure ($62m), as well as higher forecast residential subdivision and connections ($86m)
- As a result of the customer connection growth and increase in projected EVs uptake, a strong increase in system growth investment ($254m) is forecast to support large customer load requirements such as data centres and transport electrification ($71m) and large scale residential developments including Kainga Ora ($55m).
- Asset replacement expenditure is at similar level to previous forecast ($22m (2%) higher) with some additional provision for synergistic cable replacement with third party infrastructure projects to capture economic benefit of cost share and overall project cost reduction.

- The timing of asset relocation projects is dictated by third party projects and the expenditure forecast largely aligns with the previous AMP.
- With climate change and increasing adverse weather events, additional provisions are allowed to improve network resilience in distribution overhead line hardening ($70m), sub-transmission undergrounding ($105m), and relocation and elevation of zone substations to mitigate the risk of flood and inundation ($14m).

15.3.2 EXPLANATION OF MAJOR NON-NETWORK CAPEX VARIANCES

Key changes in Non-network CAPEX over the 9 years for which the 2022 AMP and 2023 AMP overlap are as follows:

- An increase in network digital expenditure of $21.3m, is largely attributed to:
  - Continued modernising IT/OT Network infrastructure: With the increasing number of threats and their severity, Vector is forecasting an increased expenditure of $12.2m to ensure investments in platforms in both the IT and OT networks are protected.
  - Data Centre move of Vector's main data centre out of Vector's Head Office to a more fit for purpose facility $6.8m
- ADMS Phase II investment has moved to a later period following on from the implementation of the foundation Phase I investment. ADMS Phase enables the efficient operation and integration of Outage Management (OMS) and Switch Order Management (SOMs) as part of an Advances Distribution Management System - $13.m
- GIS investment in the GIS upgrade following detailed design exceeded original projections - $3.5m
- Data use cases and data platform improvements required to support data driven decision making as well as laying the foundations for LV and DER visibility initiatives into the future - $2.5m
- Investment in planning and operations tools needed to support these operations at scale - $1m
- Continued and increased investment in the lifecycle of many digital platforms in 3-5 years as there is not only future uncertainty but also currently unknown technologies that will be available to deliver better outcomes. Using our Value Stream construct, we have increased the expenditure allocated to each value stream to replace and upgrade platforms based upon this lifecycle. The increase in forecasted investment is approximately $4.1m.
- Property and leasing costs have increased by $5.6m compared to the previous AMP due to:
  - an updated assumption for the warehousing lease. Due to COVID-19, a new lease arrangement is planned for FY24, which will accommodate an increase in stock holding and will renew in 10 years.

15.4 OPEX forecast

The forecast OPEX during the next 10-year planning period are presented below, based on our key asset maintenance standard and operational structure. These are grouped in the following categories:

- Network OPEX – discussed in Section 8
- Non-network OPEX – discussed in Section 14

15.4.1 TOTAL OPEX

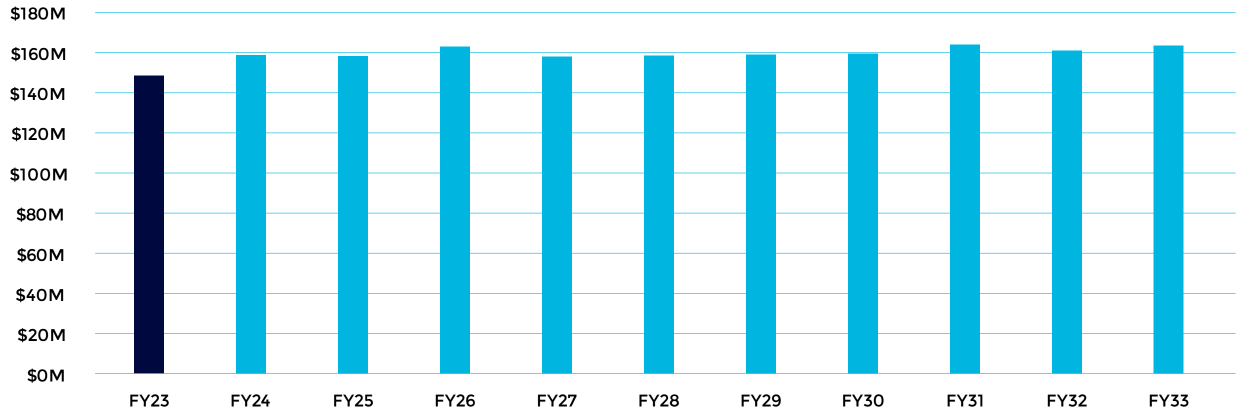


FIGURE 15.7: TOTAL OPEX (FINANCIAL YEAR, $'000 CONSTANT FY23)

The total OPEX expenditure profile is relatively consistent over the AMP horizon with a small increase in FY24 – FY26 due to asset replacement and renewal work and in FY26 / FY31 / FY33 due to routine and corrective maintenance inspections.

15.4.2 NETWORK OPEX

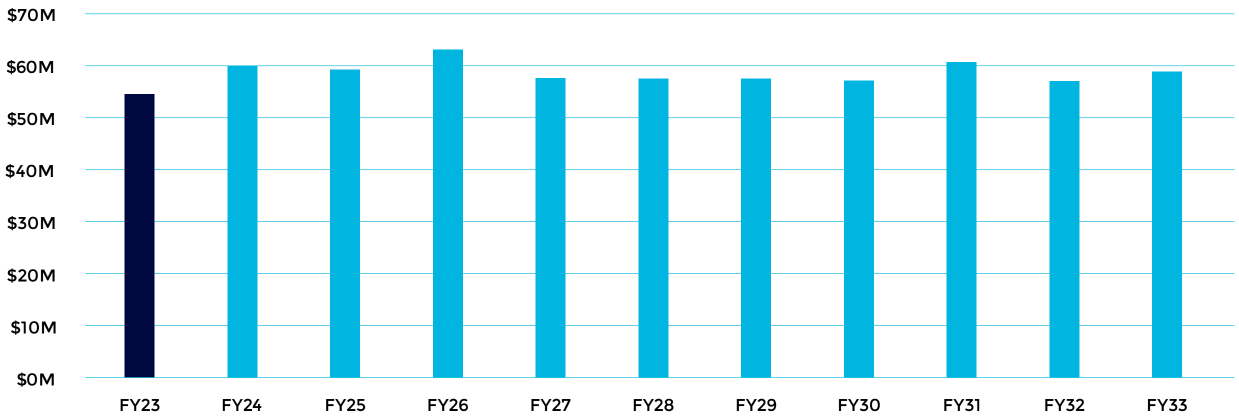


FIGURE 15.8: NETWORK OPEX (FINANCIAL YEAR, $'000 CONSTANT FY23)

The network OPEX forecast expenditure is consistent with FY22 expenditure and is underpinned by the latest asset maintenance standards. Over the 10 year planning period the expenditure profile is relatively consistent with small increases in FY24 – FY26 due to asset replacement and renewal work and in FY26 / FY31 / FY33 due to routine and corrective maintenance inspection work as a result of the Risk Based Approach (RBA) introduced as part of the SAP PM system implementation.

15.4.3 NON-NETWORK OPEX

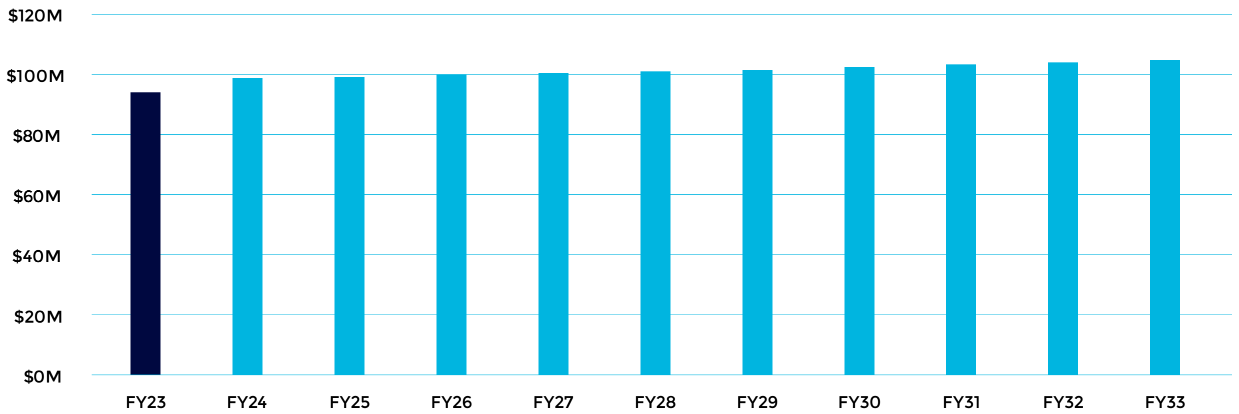


FIGURE 15.9: NON-NETWORK OPEX (FINANCIAL YEAR, $'000 CONSTANT FY23)

Non-network OPEX forecast expenditure is trending slightly higher over the AMP period due to expected higher levels of insurance, network data costs and meter data.

15.5 OPEX forecast variance to previous AMP

The forecast OPEX during the next 10-year planning period is broken down into the key asset categories defined in the Commerce Commission's Electricity Distribution Information Disclosure Amendments Determination 2012 and shown in Table 15-3.

Figure 15-10 shows the difference between the 2023 and 2022 AMP expenditure forecasts year on year, with Table 15-4 breaking down the variance by expenditure categories.

AMP 2023 OPEX FORECAST

AMP23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Service Interruptions and emergencies	15,785	15,615	15,736	15,859	15,982	16,107	16,233	16,360	16,488	16,618
Vegetation management	5,500	5,500	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000
Routine and corrective maintenance and inspection	22,452	22,055	24,817	22,768	22,929	22,703	22,630	25,982	22,157	23,728
Asset Replacement and renewal	16,058	15,952	15,443	11,833	11,523	11,616	11,133	11,222	11,313	11,404
System operations and network support	51,648	51,857	52,530	53,018	53,372	53,826	54,669	55,298	55,779	56,457
Business Support	46,958	47,037	47,131	47,235	47,352	47,478	47,614	47,761	47,919	48,089
Total OPEX	158,401	158,016	162,657	157,713	158,159	158,731	159,279	163,623	160,655	163,296

TABLE 15-3: OPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY23)

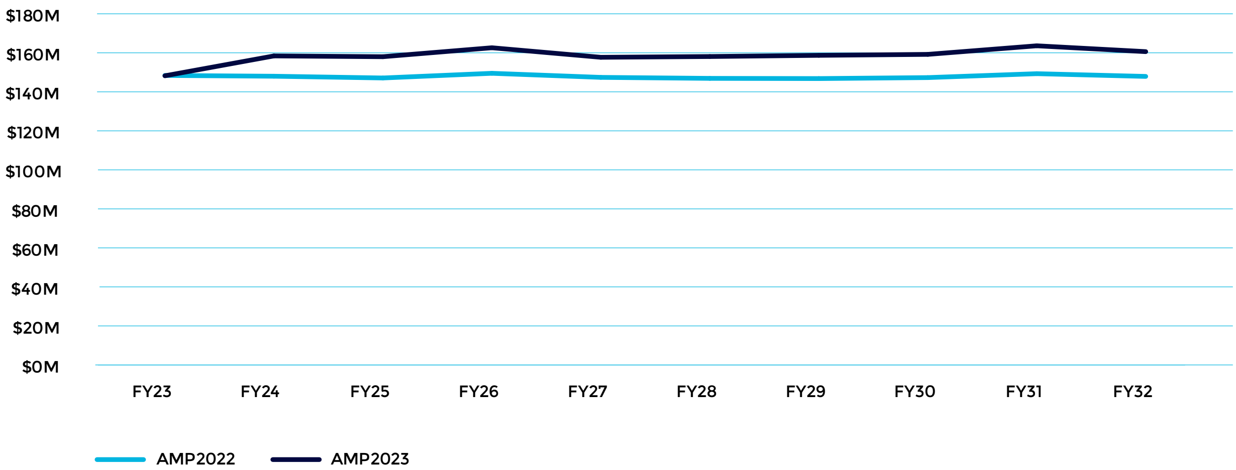


FIGURE 15.10: AMP 2023 VARIANCE TO AMP 2022 OPEX FORECAST CHART (FINANCIAL YEAR, $M CONSTANT FY23)

AMP23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	TOTAL
Service Interruptions and emergencies	(847)	(563)	(570)	(577)	(584)	(591)	(599)	(606)	(613)	(5,550)
Vegetation management	(69)	(202)	(1,819)	(1,920)	(2,020)	(2,118)	(2,213)	(2,307)	(2,399)	(15,067)
Routine and corrective maintenance and inspection	(864)	(395)	(1,110)	(893)	(852)	(658)	(458)	(1,756)	237	(6,750)
Asset Replacement and renewal	(933)	(1,570)	(1,062)	2,367	1,633	1,540	2,024	1,934	1,844	7,777
System operations and network support	(2,735)	(3,206)	(3,527)	(4,101)	(4,104)	(4,643)	(5,131)	(5,844)	(5,968)	(39,258)
Business Support	(4,867)	(4,947)	(5,040)	(5,145)	(5,262)	(5,388)	(5,523)	(5,670)	(5,828)	(47,669)
Total OPEX	(10,314)	(10,883)	(13,127)	(10,269)	(11,189)	(11,857)	(11,901)	(14,249)	(12,728)	(106,518)

TABLE 15-4: AMP 2023 VARIANCE TO AMP 2022 OPEX FORECAST (FINANCIAL YEAR, $'000 CONSTANT FY23)

15.5.1 EXPLANATION OF MAJOR NETWORK OPEX VARIANCES

Key changes in Network OPEX over the 9 years for which the 2022 AMP and 2023 AMP overlap are as follows:

- $5.5m increase in Service interruptions and Emergencies expenditure is largely attributable to an increase in exceptional maintenance expenditure provided for major weather-related events.
- $15.1m increase in vegetation expenditure is due to the inclusion of CPI component on future spend and an additional $1.5m per year from FY26 for network resilience for expected increase in future weather-related events.
- An increase of $6.7m in Routine and Corrective Maintenance is largely due to time and materials planned maintenance activities reallocated from corrective maintenance (included in asset replacement & renewal) offset by lower costs expected from asset refurbishments.
- An overall reduction of $7.8m in Asset Replacement and Renewal as a direct result of time and materials planned maintenance activities reallocated to routine and corrective maintenance inspection.

15.5.2 EXPLANATION OF MAJOR NON-NETWORK OPEX VARIANCES

Variances in non-network OPEX over the 9 years for which the current and prior year AMP overlap, reflect the following key changes:

- Systems operations and network support expenditure is forecasted to be $39.2m higher as a result of the removal of supplier rebates, increased insurance premiums and higher network data costs.
- A forecast increase in Business Support expenditure of $47.7m driven by increased investment in digitalisation as well as increased costs due to SaaS services being now being recognised as OPEX. In addition to this, allocated corporate costs have increased due to higher insurance premiums, personnel costs and professional fees.

15.6 Inputs and assumptions

This section outlines key inputs and assumptions used for the forecast expenditure in the AMP planning period. Estimates for projects and programmes for the first few years in the AMP period receive a higher level of scrutiny during the compilation of estimates and thus have a higher level of accuracy than projects in the latter years.

15.6.1 NETWORK CAPITAL EXPENDITURES

SPECIFIC PROJECTS

The requirement to invest capital for specific individual projects is either borne out of large customer connection requests, asset relocations triggered by third party infrastructure projects, asset condition and failure risks and network system reinforcement requirement for security of supply.

Vector has extended the use of Condition Based Asset Risk Management (CBARM) modelling to primary assets including indoor primary switchgear and subtransmission cables. As well as distribution assets for the programme of work (section below) to support and prioritise asset replacement requirements over the 10-year forecast horizon.

The CBARM models are based on the principles and calculation methodologies outlined in the OFGEM DNO Common Methodology and tailored to reflect Vector's operational environment. The models incorporate Vector's input data such as historical failure rates, to predict the volume of assets that will need to be replaced and thus the level of investment needed to manage each of the asset fleets. Historical actual costs are used as the basis for the unit cost applied in the forecast expenditure.

The assumptions and processes that build up the reinforcement expenditure are detailed in section 10.4. It is initiated by an annual assessment of the customer peak loading on all distribution feeders and zone substations. Any capacity shortfalls and breaches of our security of supply standard are identified through network constraint modelling and solutions are assessed and proposed through investment option analysis.

Cost estimation for significant capital projects (greater than $1m) involves site inspections to determine constraints and risks. From this, a scope and constraints summary is compiled with a relatively detailed project estimate. The cost estimate is built with a bottom-up approach using a standardised cost estimating model, which draws the inputs from the moving cost from SAP inventory data for materials and plant, standard rates for internal staff time writing and standard agreed rates for external commissioning support and contracted project management.

PROGRAMMES OF WORK

Forecasting for volumetric programmes of work applies to most of Vector's customer connection expenditure and investment relating to Vector's distribution assets.

The forecast for customer connections volumes is supported by data from the Auckland Forecasting Group (AFG). The assumption for consents converting to gross connections has dropped in the medium term from the prior year but expected to rise back up in the long term. The cost estimates for customer connections are based on an average cost using historical data.

For distribution assets, Vector has continued with the use of CBARM models for asset classes including distribution ring main units, distribution transformers, overhead conductors, and overhead 11 kV switchgear to inform the forecasted volume of assets to be replaced and/or remedied during the AMP cycle.

15.6.2 NETWORK DIGITAL ASSUMPTIONS

Given the fast-changing landscape, the uncertainty in investments increases with time. There is reasonable certainty for the investments in the initial 18-24 months with less certainty beyond that. The investment forecasts provided are based on current knowledge based upon projects being currently undertaken and market conditions. Vector has a standard quarterly planning process that reviews investments, reprioritises as required and follows a business case process to proceed with investments.

Key assumptions in our forecasts include support for all existing platforms is provisioned thus not requiring unexpected replacement. Specifically, current SAP version support will continue through to 2027. In addition cybersecurity threats will remain at a level where current investment forecasts are sufficient to protect Vector systems and respond to incidents within the IT domain. Investment forecasts do assume increased investment in OT Cybersecurity controls as the number of sensors and devices connecting to the OT network increases. The Electricity business will need to leverage modern automation technology and tools to be able to scale its operations efficiently to meet growing consumption demand Vector operations will require investment to facilitate the scalability necessary to service increased connections and increased consumption over the next 10 years.

15.6.3 PROPERTY AND LEASES

The mitigation of risks associated with COVID-19 has been the major impact on the assumptions in the lease and property forecasts. Larger warehousing arrangements for increased stock holding to minimise the impact on the supply chain has been assumed. Also, no significant changes have been made to the forecasts for the expected Head Office move in RY24 as operating costs are expected to be in line with current levels of spend. Relevant capital expenditure related to the Head Office move has been included in the CAPEX forecast.

15.6.4 OPERATING EXPENDITURES

To a large extent, the network operating expenditure relates to a programme of planned maintenance work driven by a suite of maintenance standards and a risk-based approach to corrective asset maintenance. To this end, our planned maintenance network operating expenditure forecast has been constructed bottom-up, taking into consideration the various activity unit rates, frequencies and the quantum of activities.

We have constructed the non-network operating expenditure forecast primarily based on the existing operating structure with modifications for known changes and excludes one-off transitional type cost items. Further, in certain instances, we have relied on historical averages to form a baseline view, where we believe forecasting the expenditure items with a reasonable degree of accuracy is challenging.

SECTION 16

Programme delivery

16 –Programme delivery

16.1 Overview

This Section provides an overview of the processes used to manage the delivery of our capital works and maintenance works programmes. It provides an overview of our Programme Delivery process that enables us to consistently deliver our work safely, to quality, cost effectively and to schedule. We also provide an overview of our approach to prioritizing works and optimizing resources for delivering our works programme as well as the challenges that we face in terms of improving the reliability and resilience of our network, especially in light of the recent Covid-19 pandemic, and more recently the impact and effect of flooding across Auckland in late January 2023 and Cyclone Gabrielle in February 2023. Finally, we provide an overview of our use of standardised equipment types and standardised equipment ratings and sizes, approach that assists in minimising inventory costs and critical spares inventory.

16.2 Capital works delivery

Capital Delivery is the delivery of the annual capital programme including project engineering, project management, procurement of equipment, tendering of capital works, and financial control and governance..

CAPITAL PROJECT GOVERNANCE

Vector has well defined and embedded processes for identifying network upgrade needs and capital justification to achieve its business objectives and reduce network risk. Our network investment planning and project delivery follows a stage-gate governance approval process. The process, shown in Figure 16.1, covers all expenditure and consists of five approval 'gates' that are governed by the Delegated Authority Framework. Our SAP workflow mirrors this approval stage gate process for budget applications. The first three gates relate to the identification of the risk and need for a project or program, analysis of the options for the works and development of the preferred solution. A Capital Expenditure Justification (CEJ), essentially a business case to gain approval to undertake capital investment, together with a detailed cost estimate, are the artefacts that are developed to demonstrate prudence and efficiency of expenditure and that the governance process has been followed.

FIGURE 16-16.1: PROJECT LIFECYCLE

Project progress is recorded and monitored using an enterprise-wide project management tool [1] and undergoes a monthly review. Exception reporting is provided to the Executive and Board monthly, covering; HSE, performance against schedule, financial performance, issues, challenges and risks. HSE and risk are also reported through to the Board using our risk software application known as ARM (Active Risk Manager). Risks are escalated to the Board Risk Committee as required.

Monthly reviews of each project are carried out by the Programme Management Office (PMO), a division within the Capital Delivery Team, to ensure that projects are going to plan and identify issues, constraints and challenges. The performance of projects in delivery is also reviewed through a series of monthly contractor performance meetings attended by the Manager Capital Programme, respective project managers and representatives from the contractors. Contractual issues are dealt with directly by Project Managers and the engineer to the contract and if necessary, escalated to the Team Leaders within the Capital Delivery Team.

An internal Governance Group (GG) that includes representatives of the Network Performance team, Capital Investment team, Finance Team and Major Projects team, meet every week to discuss new scopes of work, financial year and regulatory delivery and financial targets, DPP period spends vs. budget and discuss exceptions and manage scope changes via a formal change control process. The GG is chaired by the PMO lead.

Approvals are required before any commitment is made. Approvals are governed and must follow Vector's Procurement Policy and Delegated Authority Framework.

The capital works delivery process includes five primary stages: Risk assessment and project identification, Scoping, Feasibility Assessment, Procurement, and Delivery (Construction, Commissioning and Closeout). Table 16-1 provides an overview of the processes undertaken under each of these phases.

[1] Project-on-line

PHASE	ACTIVITY OVERVIEW
Identification of network risk and the need for a project or program	• Network risk, network need requirement and options analysis • Project prioritisation • Establish base cost estimate • Needs statement • Recommendation for inclusion in Asset Management Plan (AMP)
Scoping	• Development of initial (preliminary) project scope • Cost estimation • Assessment of alternate project options • Determination of key project risks • Procurement analysis (identification of long lead time items) • Prepare Development Funding Application (CEJ)
Feasibility	• Identification and assessment of project-specific risks/issues • Surveying and/or Geotech investigation, flood risk assessment etc. • Early Contractor Investigations • Design concepts development and review • Safety in Design (SID) • Finalise project scope • Detailed design • Cost estimation and detailed materials list • Early procurement (long lead time items only) • Prepare Full Funding Application (CEJ) – Business case
Procurement	• Assess supply chain risks and delivery times • Tendering for construction • Procurement tendering • Preparation of contract documentation
Delivery	• Cost, Schedule and Quality performance monitoring • Risk and issues management • Construction • Commissioning • Handover / Project close

TABLE 16-1 PROJECT LIFECYCLE DELIVERABLES

16.2.1 SUPPLY CHAIN MANAGEMENT

Over the last three years Vector has worked with suppliers and field service providers to reduce risk and complexity in our supply chain. The Covid-19 pandemic presented significant operational challenges including constrained supply, increased freight costs and longer delivery times. Vector has overcome these challenges by building deeper, more transparent relationships with trusted suppliers, forecasting demand for long lead time items, rationalising the range of "standard" items purchased and introducing new suppliers and diverse supply routes to mitigate the impact of bottlenecks.

The risk of delay to physical works due to long lead times on equipment is mitigated using inventory of commonly used items and, for one-off items such as primary switchgear for substations, by ordering equipment as early as possible.

We have standardised equipment configurations to reduce the variety of materials used, enabling diversification of sourcing through minimum specification levels in place of Vector-only custom builds. Inventory of frequently used items such as distribution transformers and switchgear enables forecast project and network maintenance requirements to be met from stock. We have invested in building supply chain management systems and capability to transition from a just-in-time ordering model to an integrated business planning process which aggregates demand projections from planning, delivery and operations functions to forecast demand requirements. An overhauled process for the introduction of new equipment to the network not only validates technical efficacy but also operational impact, whole of life value and network need.

Our suppliers have diversified freight routes and sourcing over the last three years to mitigate risk. Suppliers are now starting to report a slow reduction on shipping lead times, risk and cost, although demand continues to exceed manufacturing capacity. Lead times for commonly used equipment have increased by up to 800% over the last three years, so that purchase orders for inventory rely on seasonal/programme/contextual demand signals rather than actual planned requirements. Work this year to improve the quality and relevance of supply chain data will help to improve the reliability of these signals.

Most of the distribution equipment required for Vector's capital, customer and maintenance delivery programmes is sourced by Vector and free issued to contractors for installation. Less complex, high volume equipment such as poles and cross arms are sourced by contractors, to Vector's specifications, with the cost passed through to Vector when the item is installed. Procurement of the works is through our MUSA contract using our FSPs for maintenance works and NZ3910 contracts with four panel members for capital works.

16.2.2 CUSTOMER INITIATED CAPITAL PROJECTS – CUSTOMER DELIVERY TEAM

The Customer Delivery team delivers customer-initiated capital projects like subdivisions and commercial connections. We use an outsourced delivery model where our Field Service Providers (FSPs) design and deliver works by geographic region. With around 800 customer-initiated projects per year, the FSPs knowledge of the local network is critical in delivering these smaller, short-duration capital projects effectively.

Within Vector we have a team of customer advisors that administer the project delivery and maintain the interface with the customer and liaise with the Planning team and Capital Investment team.

The Multi-Utility Services Agreement (MUSA) capital works job sheet provides a simple and well-understood contract engagement that reduces the administrative costs associated with tendering works while ensuring we demonstrate value for money through comparison with similar recent works and standard negotiated rates.

RESOURCE SCHEDULING

The priority of customer-initiated projects is generally governed by when the client contracts Vector to deliver the works. FSP resource levelling and outage scheduling are then used to fine-tune delivery scheduling.

FEASIBILITY AND DETAILED DESIGN

The electrical design of projects delivered by the Customer Delivery Team consist mostly of distribution designs that includes an 11k V network, distribution substations and a low voltage distribution network. These designs do not require a multi-disciplinary approach and its singularity of design is ideally suited for design by our FSPs. If a customer- initiated project requires multi engineering disciplines to be involved say for example a large datacentre that requires structural, civil, protection and detailed substation designs, such a project will be delivered by the Major Projects Team. The design and capital project cost is presented to the client as our offer to complete the works.

DELIVERY

In the past Vector traditionally relied on two FSPs for the delivery of all customer-initiated works. However, additional service providers are being brought onto line to assist to deliver the increasing number of customer capital projects.

Vector's customer advisors use our Customer Management application, Siebel, to monitor project progress through the various delivery stages. Change control of projects within the Customer Delivery team is generally through a client agreed variation.

Our FSPs commission equipment being brought onto the network to ensure it complies with our standards and can be operated and maintained safely. Once complete they update Vector's information systems and hand the installation over to Vector's Electricity Maintenance team.

16.2.3 MAJOR CAPITAL PROJECTS – MAJOR PROJECTS TEAM

Major capital projects are works identified from an assessment of network risk, high level assessment of a solution, and the project is then ranked, and included and scheduled in the AMP for capital delivery. Major capital projects are delivered by the Major Projects Team. However, large customer-initiated projects that require multi discipline engineering input and thus higher commercial risk fall outside the realm and scope of works for the Customer Delivery Team and are delivered by the Major Projects Team.

We use a mixture of in-house project managers (PM) and contracted project managers to manage the delivery of projects. This enables us to closely match capability and capacity.

To generate competitive tension while ensuring that we maintain extremely high quality and safety standards, we tender works through two closed contracting groups:

1. **Electrical** – We retain a panel of four specialist electrical contractors. These contractors were pre-approved under a five-year umbrella agreement. Work is competitively tendered within the panel with no guarantee of work volume. These contractors are free to subcontract elements of the work but are required to initially seek subcontractors that are part of a pre-qualified specialist pool. This ensures that works are carried out by contractors that are familiar with our processes and critical risks.
2. **Specialist and civil contractors** – We have a pool of specialist and civil contractors; containing pre-qualified builders, designers, civil works contractors, consultants and specialists. Maintaining this restricted pool of contractors helps us maintain our quality and safety standards and provides the contractors with the confidence to invest in processes, equipment and people that will enable them to deliver high quality work safely. There is no overarching agreement with these contractors or any workflow commitment.

To help our contractors manage their workflow we provide a forward works view looking out 18 months in six-month horizons. Additionally, all our major projects are published on the Auckland Council's Forward Works viewer to help identify synergies across electricity, gas, and other utility projects.

Due to the higher volumes of work carried out by the electrical contractors they are also provided with a monthly report showing our tender schedule.

RESOURCING AND SCHEDULING

Resourcing and scheduling of major projects is managed by the Project Management Office (PMO) division within the Major Projects Team. The delivery schedule is based on the AMP and the priorities and timelines set in the AMP. The PMO uses the Microsoft 'Project Online' application as our Project Portfolio Management tool to schedule and track our works.

The PMO uses the priorities set out in the AMP, by our Network Planning team, to provide an outline programme which is optimised by the delivery team based on outage constraints and resource availability. The schedule is compiled in conjunction with the Network Performance and Planning teams. Vector has an in-house team of project managers but external project managers are contracted in as required to provide additional PM resources to deliver project surge programs.

SCOPE OF WORKS AND DESIGN

The delivery of a major capital project is initiated when a scope of works is delivered to the PMO office. The PMO office converts the scope to a project brief which is issued to the assigned project manager (PM). A project is then "kicked-off" in a meeting that is attended by all stakeholders e.g. the project owner (the scope author), and other representatives from within Vector as appropriate (e.g. Protection and Control team, Operational Team, etc.). Thereafter concept designs are developed which goes through a stage-gate design review cycle and safety in design reviews. These are then converted into detail designs.

Vector has a pool of electrical, civil and structural engineers for detail designs. During the life of a project the project owner and various asset specialists for the different asset classes provide input and reviews to designs but the contracted consultants and stage gate meetings are managed by the PM.

PROCUREMENT OF WORKS DELIVERY

Depending on the nature and scale of a project we have the option to tender projects to our panel of electrical contractors or directly to our special pool. A modified NZS 3910 invitation to tender is sent to the contractors. Generally, we allow six weeks for the contractor to prepare their offer. The tender period will increase or decrease depending on the complexity of the works and/or the volume of tenders in progress.

The contractor's offer is provided electronically in two parts: non-priced information and priced information. The tendering process is controlled by the PMO and once the contractor's offer is received a PM leads a team that assess the offer. The non-priced sections of the offer are assessed before the PM being provided with the priced information. This ensures we focus on the quality of the solution before we consider the price. Once an offer has been selected, we engage the contractor using a modified NZS 3910 contract.

DELIVERY

Our project managers have an active role in every step of the delivery of their projects. Our project delivery model is based around the PMI delivery framework, using an Enterprise-wide portfolio management application to track and monitor projects. Additional support is provided through an internal team, including HSE, procurement, Engineer to Contract, RMA, quantity survey and risk specialists.

Projects are reviewed by the Major Projects team on a monthly basis. The PMO office leads the reviews. The reviews include the following:

- Project health checks are produced by the project manager and the contractor. These are reviewed by senior members of the team and discussed at regular performance meetings with each contractor.
- Project schedule performance is tracked and reported monthly. Vector's executive team receive a monthly exception report.
- Financial performance is tracked monthly by the PMO and at any significant commitment change.

The Governance Group meets on a weekly basis to review change controls, specific challenges that could delay projects, and cost overruns. (see Capital Project Governance under clause 16.2 above).

COMMISSIONING

A risk register and engineering log are kept throughout the life of a project. When a project is complete and commissioned a final site over walk through and inspection is held. The meeting is attended by the in-house asset specialists for the different asset types and disciplines, design consulting engineers and contractor. Issues that were registered in the risk register and engineering log are checked for resolution, completion and compliance.

The general quality of the works is also checked, and "snag" lists compiled as necessary. Once all outstanding issues have been resolved the project is formally handed over handed to the Electricity Operations and Maintenance Team. Commissioning is undertaken in line with commissioning standards and specific equipment requirements. The last step is a lesson's learnt session and the issuing of a lessons learnt report.

16.3 Maintenance works delivery

16.3.1 FIELD SERVICE MODEL

Vector has four main field service providers who undertake maintenance activities on Vector's behalf:

- Electrix Ltd is Vector's maintenance contractor for the Northern network area;
- Northpower Ltd is Vector's maintenance contractor for the Auckland network area; and
- Treescape Ltd is responsible for maintaining trees encroaching on electricity networks.
- Asplundh Ltd is also responsible for maintaining trees encroaching on electricity networks. Asplundh focuses on vegetation management in the Northern network (i.e. the Electrix "patch")

Electrix and Northpower operate under the Multi-Utility Services Agreement (MUSA). The scope of the electricity maintenance contracts is to deliver the reactive, preventative, corrective and reactive maintenance works programmes, based on the requirements set by our suite of maintenance standards.

Our Operations and Maintenance Team is responsible for managing the relationship coordination and performance of our service providers.. The MUSA contract defines the responsibilities, obligations and Key Performance Indicators (KPIs) to complete scheduled works. Vector maintains a library of maintenance standards which contractors must comply with when performing their duties.

Treescape and Asplundh operate under separate services contracts managed by our Operations and Maintenance Team. The prioritization of tree maintenance is guided by an external service provider, Arborlab Limited, who use a combination of tree fall risk, potential SAIDI impact, safety, etc. to establish the forward programme of vegetation control work activities.

The delivery of all these maintenance activities is closely monitored and adjusted by Field Services, monthly, to ensure the agreed annual target volumes are achieved. 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 (via a CAIDI KPI) are the core measures.

Standard rates for prescribed activities are reviewed on an annual basis. Out of cycle rate increases or new rates arising from changes to standards, legislative requirements or other special circumstances are negotiated and managed using the contract change management process

16.3.2 GOVERNANCE – REPORTING AND APPROVALS

Performance against the annual budgets is closely monitored, with formalised change management procedures in place. Regular reports monitor:

- Health, safety and environmental issues;
- Monthly overall expenditure against budget;
- Reliability performance – SAIDI, SAIFI, CAIDI;
- Progress with risk register actions (the board has a risk committee with a specific focus on risks to the business); and
- Progress by the Strategic Reliability Management Plan of identified actions

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

16.4 Equipment selection

16.4.1 USE OF STANDARDISED EQUIPMENT TO MINIMISE COSTS

We have a policy of using standardised equipment sizes and types on our network to minimise long-term costs and keep a check on stocks of spare parts. Also, when specifying equipment, we consider climate change by seeking to understand the potential changes to environmental conditions that could impact our assets such as extended long periods of high temperatures, high winds and low rainfall.

The following gives a high-level overview of some of our equipment selection strategies. Further details are provided in Section 12 (Asset Replacement and Renewal).

Transformers: Since 2000, we have standardised our fleet to 15MVA and 20MVA power transformers but in 2021 it became clear that a larger transformer is required to supply the demand. A 28MVA unit has been added as a standard transformer model. The power transformer technical specification was recently updated to include the latest technical requirements.

With regard to distribution transformers, we have rationalised our type and ratings of distribution transformers to reduce the requirement to hold many types under strategic stock.

Subtransmission Cables: Our subtransmission cable range has been standardised to a certain range. The standard range mitigates the requirement to hold multiple types of cables in strategic stock. For new subtransmission reinforcement or subtransmission cable replacement projects, the cable and its installation parameters are modelled to ensure target network ratings can be achieved under various ground moisture conditions using our in-house CymCap cable-rating software. Moisture levels, field-tested ground thermal conductivity results, cable laying installation method and proximity of other cables are all input into the model.

Distribution cables and overhead conductors: Similarly to subtransmission cables we have standardised and rationalised our range of low voltage underground cables and overhead conductors. This negates the need to hold multiple types in strategic stock. The requirements for the type of cable or overhead conductor to be installed in a project are modelled using our Powerfactory Digsilent network modelling software.

Communications: Our communications network routers, switches, antennae, synchronous clocks, media convertors and power quality meters have all been standardised to a simple and rationalised range. This makes procurement simple and quick and makes holding of spares small in scale.

Automation systems: For our remote terminal units (RTUs) we have standardised on two types from two different manufacturers. Each of the types are covered under its own standard design. For our transformer management system (TMS) equipment we have also standardised on two types from two different suppliers each with its own standard design. The selection of two types for each of the automation systems provides options with the present supply chain constraints.

Auxiliary systems: We have standardised secondary systems on switchgear to be powered using 110 V DC systems. Our program of works to replace ageing battery chargers and controllers at our zone substations is almost complete. All new zone substations will be fitted with 110V DC systems. Where switchgear is upgraded or refurbished or new protection schemes installed, legacy 24V DC and 30 V DC systems and voltage transformer supplied DC systems are replaced with 110V DC systems. Our DC systems are equipped with battery monitoring devices.

Buildings: Our zone substation buildings have a template design standard approach to minimise the cost and complication of bespoke engineering, design and construction.

SECTION 17

Appendices

17 –Appendices

17.1 Appendix 1 – Glossary and terms

AAAC	All Aluminium Alloy Conductor
AAC	Aluminium Alloy Conductor
ABC	Aerial Bundled Cable
ABI	Air break isolator
ABS	Air break switch
AC	Alternating current
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
ADSL	Asymmetric Digital Subscriber Line
AFG	Auckland Forecasting Group
AIS	Air-insulated switchgear
AKL	Auckland
ALR	Auckland Light Rail
AMETI	Auckland Manukau Eastern Transport Initiative
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset management plan
AMS	Asset Management Standard
ARM	Active Risk Manager
ARP	Asset replacement project
AS/NZ	Australian/New Zealand Standard
AT	Auckland Transport
BESS	Battery Energy Storage Solutions
BI	Business Intelligence
BRAC	Board Risk and Assurance Committee
BSP	Bulk supply point
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).
CAB	Citizens Advisory Board
CAD	Computer Aided Design
CAIDI	Customer average interruption duration index
CAPEX	Capital expenditure
CB	Circuit breaker
CBARM	Condition based asset risk management
CBD	Central business district
CCT	Covered conductor type
CDEM	Civil Defence and Emergency Management
CEJ	Capital Expenditure Justification
CEMS	Customer Effort Mean Score
CEO	Chief Executive Officer
CGPI	Capital Goods Price Index
CM	Corrective Maintenance
CO2e	Carbon Dioxide Equivalent
COO	Chief Operating Officer Electricity, Gas, Fibre

CRL	City Rail Link
CRLL	City Rail Link Limited
CRM	Customer relationship management
DA	Delegated Authority
DAF	Delegated Authority Framework
DC	Direct current
DER	Distributed energy resource
DERMs	Distributed energy resource management system
DGA	Dissolved Gas Analysis
Distribution substation	A substation for transforming electricity from distribution voltage (22 kV or 11 kV) to 400V distribution voltage.
DMR	Digital Microwave Radio
DNO	Distribution network operator
DP	Degree of polymerization
DPP	Default price-quality path
DPP2	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2015 to 31 March 2020
DPP3	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2020 to 31 March 2025
DPP4	The price-quality path set under Part 4 of the Commerce Act for the period 1 April 2025 to 31 March 2030
DSM	Demand Side Management
EDB	Electricity distribution business
EECA	Energy Efficiency and Conservation Authority
EGF	Electricity, gas, and fibre
EIM	Enterprise Information Management
EIPC	Electricity Industry Participation Code
ENA	Electricity Networks Association
ENS	Electricity Network specification
EOC	Electricity Operations Centre
ERM	Enterprise Risk Management
ERP	Enterprise resource planning
ESE	Electricity Standard Engineering
ESM	Electricity Standard Maintenance
ESS	Electricity Standard Specification
EV	Electric vehicle
FCAS	Frequency control ancillary services
FENZ	Fire and Emergency New Zealand
FMEA	Failure Mode Effect Analysis
FNR	Future Network Roadmap
FPI	Fault Passage Indicator
FSP	Field Service Provider
FY	Vector financial year (year ending 30th June)
GHG	Greenhouse Gas
GIS	Geographic information system
GOS	Grade of Service
GXP	Grid Exit Point
HILP	High impact low probability
HR	Human resources
HSE	Health, safety and environment

HSNS	High Speed Network Services
HSWA	Health and Safety at Work Act
HV	High voltage: a nominal AC voltage of 1000 volts and more
HVAC	Heating, Ventilation and Air Conditioning
HV-GIS	High voltage gas insulated switchgear
HWLC	Hot water load control
ICCC	Interim Climate Change Committee
ICP	Installation control point
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEECP	Institute for European Energy and Climate Policy
IND	Industrial
IP	Internet Protocol
IPCC	Intergovernmental Panel for Climate Change
ISO	International Organization for Standardization
IT	Information Technology
KPI	Key Performance Indicator
kV	Kilovolt
kW	Kilowatt
LAN	Local area network
LBS	Load break switch
LCI	Labour Cost Index
LiDAR	Light Detection and Ranging
LRT	Light Rail Transit
LV	Low voltage – a nominal AC voltage of less than 1000 volts
MO	Minimum Oil
MSM	Macro Strategic Model.
MUSA	Multi-Utility Services Agreement
MV	Medium voltage
MVA	Megavolt amperes
MW	Mega Watt
MWh	Megawatt Hour
National grid (or grid)	The 110 kV and/or 220 kV 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.
NBS	New building standard
NIWA	National Institute of Water and Atmospheric Research
NPV	Net present value
NTHN	Northern
NWA	Non-Wires Alternative
N-x security	Subtransmission security class rating.
NZS	Standards New Zealand
NZSEE	New Zealand Society of Earthquake Engineering
NZTA	New Zealand Transport Agency
OD	Outdoor
ODID	Outdoor to Indoor
ODV	Optimised deprival value
OEM	Original equipment manufacturer

OH	Overhead
ON	Oil Natural
ONAF	oil natural air forced
ONAN	oil natural air natural
OPEX	Operational Expenditure
OT	Operational Technology
PD	Partial Discharge
PE	Polyethylene
PI	Plant Information
PICAS	Paper Insulated Corrugated Aluminium Sheath
PII	Personally Identifiable Information
PILC	Paper insulated lead sheath
PM	Planned Maintenance
PMI	Project Management Institute
PMO	Programme Management office
PPI	Producer Price Index
PQM	Power Quality Meter
PV	Photovoltaic
PVC	Polyvinyl acetate
QTRA	Quantitative Tree Risk Assessment
RAB	Regulatory Asset Base
RBA	Risk Based Approach
Reliability	The ability of the network to deliver electricity consistently when demanded.
RES	Residential
Resilience	The ability of the network to recover quickly and effectively from an event.
RM	Reactive Maintenance
RMU	Ring-main Units
RNF	Reinforcement project
ROU	Right of use
RTU	Remote terminal unit
RY	Regulatory year (year ending 31st March)
SAA/SNZ HB	Standards Association Australia / Standards New Zealand Handbook
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SAP	Enterprise Resource Planning (ERP) System (SAP)
SAP PM	Plant maintenance module of SAP
SCADA	Supervisory control and data acquisition
SF_6	Sulfur Hexaflouride
SFRA	Sweep Frequency Response Analysis
SH	State Highway
SID	Safety in Design
SIP	Sandwich insulated panel
SME	Small and medium-sized enterprises
SMF	Special moment frame
SO	System Operator
SOC	Security Operations Centre
SoSS	Security of Supply Standard

SQL	Structured Query Language
SRMP	Strategic Reliability Management Plan
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.
SUBT	Subtransmission
SWA	Steel wire armoured
SWBD	Switchboard
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.
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
TCO	Total cost of ownership
TERP	Transport Emissions Reduction Pathway
TMS	Transformer Management Systems
TOTEX	Total cost of expenditure
TOU	Time of use
TRIFR	Total recordable injury frequency rate
TX	Transformer
UHF	Ultra-high frequency
UPS	Uninterruptible power supply
VAMS	Vegetation asset management strategy
VHF	Very high frequency
VOX	Outdoor deadtank circuit breaker
VSP	Vegetation Service Provider
VT	Voltage transformer
WAN	Wide Area Network
WIP	Work in progress
XLPE	Cross-linked Polyethylene
Zone substation	A substation for transforming electricity from subtransmission voltage (110 kV, 33 kV or 22 kV) to distribution voltage (22 kV or 11 kV).
ZSS	Zone Sub Station

17.2 Appendix 2 – Key asset strategies and standards

Vector has a set of asset strategies and standards that together define Vector's approach to Asset Management. An overview of the key policies and standards are set out below.

ASSET CLASS	GENERAL
Strategies	EAA010 Reliability and Resilience Strategy EAA018 Asset health Modelling Strategy
Technical Specifications	ENS-0099 General technical requirements ESP005 Technical Requirements for the connection of generation ESP009 Technical Requirements for small scale Inverter connected DG ESP010 Security of Supply EGP503 Smart Metering Guideline
Maintenance Standards	ESM001 General Maintenance Requirements
Engineering Standards	ESE001 Computer Aided Design (CAD) Drawing Standard ESE003 Electricity Network Drawing Management ESE004 Engineering Management Standard

ASSET CLASS	1XX SUBTRANSMISSION SWITCHGEAR
Strategies	EAA100 Sub transmission Switchgear
Technical Specifications	ENS-0005 Specification for 11 kV to 33 kV indoor switchboards ENS-0022 Specification for 110 kV GIS indoor switchboards ENS-0106 Specification for 33 kV outdoor circuit breakers
Maintenance Standards	ESM101 Maintenance of Primary Switchgear – MV fixed pattern ESM102 Maintenance of Primary Switchgear – 110 kV GIS ESM103 Maintenance of Indoor and Outdoor Conventional Switchgear ESM104 Primary Switchgear -Outdoor
Engineering Standards	ESE101 Primary Indoor Switchgear ESE102 Instrument Transformers Indoor ESE103 33 kV Switchyard Renewal and Extension Design Criteria

ASSET CLASS	2XX POWER TRANSFORMERS
Strategies	EAA200 Power Transformers
Technical Specifications	ENS-0124 Specification for 110 kV-22 kV two-winding power transformers ENS-0149 Specification for neutral earthing resistors ESS-0200 Specification for Two-Winding Transformer
Maintenance Standards	ESM201 Maintenance of Transformers 22-110 kV Power Transformers in Zone Substation
Engineering Standards	ESE201 Power Transformers Zone Substations

ASSET CLASS	300 HV CABLES
Strategies	EAA300 11 – 110 kV cable systems
Technical Specifications	ENS-0032 Specification for SC-triplex 22-33 kV cable ENS-0110 Thermal backfill for underground cables ENS-0191 Specification for single core 110 kV cable ENS -0028 Testing of High Voltage Cables and Switchgear ENS -0102 Specification FOR Polymetric cable protection covers ENS-127 Specification for 11& 22 kV underground distribution cable ENS-0169 11 kV cable current ratings for planning purposes ESS301 Ducting for Electrical Installations
Maintenance Standards	ESM-301 Maintenance of cables
Engineering Standards	ESE301 Cable Support Systems-in enclosed basements ESE302 Design requirements for sub transmission and distribution cables ESE303 Installation requirements for cables and ducts

ASSET CLASS	4XX OVERHEAD LINES
Strategies	EAA400 Overhead Lines
Technical Specifications	ENS-0094 Specification for prestressed concrete utility services poles ENS-0091 Specification for treated timber utility services poles ENS- 101 Specification for Surge Arrestors ENS-0153 Specification for overhead conductors ENS-0159 Specification for galvanised steel fittings for overhead construction ENS-0160 Specification for LV ABC fittings

ASSET CLASS	4XX OVERHEAD LINES
	ENS-0163 Specification for overhead line connectors ENS-0109 Specification for helical fittings and accessories ENS-0084 Specification for pole mounted fuse carriers and links ENS-0088 Specification for overhead insulators ENS-0112 Specification for hazard marking for poles ENS-0134 Overhead conductor current ratings for planning purposes ESS -0401 Specification for hardwood and composite crossarms ESS-0402 Specification for fault passage indicators
Maintenance Standards	ESM401 Maintenance of Overhead Lines
Engineering Standards	ESE401 Overhead Line Design Requirements ESE402 Overhead Standard Design Applications ESE406 Overhead Standard Applications Structures with Streetlights ESE413 Aerial Fibre Cables Installation

ASSET CLASS	500 DISTRIBUTION NETWORK
Strategies	EAA500 Distribution Equipment
Technical Specifications	ENS-0028 Testing of High Voltage Cables and Switchgear ENS-0103 Specification for 11 kV and 22 kV distribution switchgear ENS-0154 Specification for LV distribution service pits ENS-0162 Specification for fault passage indicators ENS-0121 Specification for auto-reclosers ENS-0097 Specification for pole mounted SF_6 switches ENS-0098 Specification for sectionalisers and remote switches ENS- 101 Specification for Surge Arrestors ENS-0078 Specification for 400V underground cable ENS-0093 Specification for fluid filled distribution transformers ENS-0155 Specification for IPPCs for LV distribution Pit ENS-0170 Refurbishment of distribution Transformers and oil filled switchgear ENS-0224 Standard for Design of Customer Supply ESP001 Residential Subdivision Design Standard ESP002 Non-residential subdivision design and planning standard ESP004 LV Voltage Drop Calculation
Maintenance Standards	ESM501 Maintenance of Overhead Switchgear ESM502 Maintenance of Pole Mounted Distribution Transformers ESM503 Maintenance of Ground Mounted Distribution Equipment and Voltage Regulators ESM505 Maintenance of LV Distribution Systems ESM607 Maintenance of Earthing System
Engineering Standards	ESE501 Distribution Substations in Buildings ESE502 Outdoor Ground Mounted Distribution Equipment ESE503 Distribution Switchgear ESE504 Low Voltage Underground Distribution ESE505 Ground Mounted Distribution Transformer ESE506 Distribution Earthing

ASSET CLASS	600 AUXILIARY SYSTEMS
Strategies	EAA600 Auxiliary Systems
Technical Specifications	ENS-0080 Specification for earthing rods and accessories
Maintenance Standards	ESM601 Maintenance of DC and AC Supply Systems ESM602 Maintenance of Capacitor and Reactor Banks ESM603 Maintenance of Building Security, Air and Fire Management Systems ESM604 Maintenance of Ripple Plant ESM607 Maintenance of Earthing System
Engineering Standards	ESE601 DC Systems ESE602 AC Systems

ASSET CLASS	700 INFRASTRUCTURE AND FACILITIES
Strategies	EAA700 Infrastructure and Facilities
Technical Specifications	ENS-0206 Specification for crushed rock for switchyards
Maintenance Standards	ESM701 Maintenance of Building, Structures and Facilities ESM708 Maintenance of Minor Tunnels ESM709 Maintenance of Penrose-Hobson Tunnel
Engineering Standards	ESE701 Zone Substation Buildings ESE702 Zone Substation Grounds ESE703 Zone Substation Building Services ESE704 Zone Substation Earthing ESE002 Zone substation signage

ASSET CLASS	800 PROTECTION AND CONTROL
Strategies	EAA800 Protection
Technical Specifications	ENS-4002 Protection and Control – Protection Settings Management System ENS-4003 Protection and control – Technical documentation
Maintenance Standards	ESM801 Maintenance of Protection and Control Systems ESM804 Maintenance of Pilot Cables ESM805 Maintenance of Radio Equipment
Engineering Standards	ESE801 Protection Systems ESE802 Automation and Control in Zone Substations ESE803 Protection and Control for Overhead Distribution Feeders ESE805 Secondary Cabling ESE806 Protection distribution Substation ESE807 Protection Philosophy Subtransmission Zone Substations and Distribution ESE810 Testing and Commissioning of Protection Relays

ASSET CLASS	900 NEW ENERGY SOLUTIONS
Strategies	EAA900 New Energy Solutions
Maintenance Standards	ESM901 Generation and Energy storage ESM903 Maintenance of Residential PV and Battery Energy Systems

HEALTH, SAFETY AND ENVIRONMENT MANAGEMENT STANDARDS
HSEMS01 Management systems framework and HSE policies HSEMS02 Leadership and Accountability HSEMS03 Competence and Behaviour HSEMS04 Engagement, Participation and Consultation HSEMS05 Contractor HSE Management HSEMS06 Emergency Management HSEMS07 Wellness and Fitness to Work HSEMS08 Risk Management HSEMS09 Incident Management HSEMS10 Audits, Reviews and Performance Reporting HSEMS11 Operational Control HSEMS12 HSE in Project Management HSEMS13 Legal Compliance HSEMS14 Document, Data and Record management HSEMS15 Action Management

ELECTRICITY OPERATING STANDARDS
ESH001 Electricity Network Safety and Operating Plan EOS001 Operational Control of the Network EOS002 Release of Network Equipment EOS003 Procedures for Operations on the Vector Network EOS004 Switching Schedules and Permits Preparation Use and Operating Terms EOS006 Live Line Operating Standard EOS007 Zone Substation Access and Security EOS009 Commissioning of Network Equipment EOS010 Operational Numbering of Vector Equipment EOS011 Protocol for Communications with the Electricity Operations Centre EOS012 Operation of Ground Mounted Switchgear up to and including 33 kV EOS013 Standard Operational Terms and Abbreviations EOS014 Operation of Circuit Breakers and associated Equipment EOS015 Procedures for Operation of OH Equipment up to and including 110 kV EOS018d Tunnel Procedures Rail Maintenance Planning EOS019 Contingency Plans (36 documents)

ELECTRICITY OPERATING STANDARDS
EOS020 Procedures for Management and Operations on the Vector Low Voltage Network EOS026 Managing Asset Rating Changes

NETWORK INFORMATION STANDARDS
ECD005 HV Event Quality Assurance Process EGD003 Calculation Guidelines for Electricity Reliability Metrics ENSD001 Asset Data Standards SAP and GIS (Electricity) EOC-009 HV Event Quality Control Procedure ESD001 Functional Location Structure Electricity ESD002 Reactive Maintenance Data Standard ESD003 HV Event Data Standard ESD005 Asset Data and GIS Data Standard ESD006 Planned and Corrective Maintenance Data Standard USD003 Data Update Request Data Standard

17.3 Appendix 3 – Typical load profiles

Figures 17.1, 17.2 and 17.3 show typical demand profiles for residential, commercial and CBD customer segments.

The profiles are normalised so that the shape characteristics can be compared. The true peak demand of each profile can differ significantly between winter and summer and is discussed in the sections below.

17.3.1 RESIDENTIAL DEMAND PROFILE

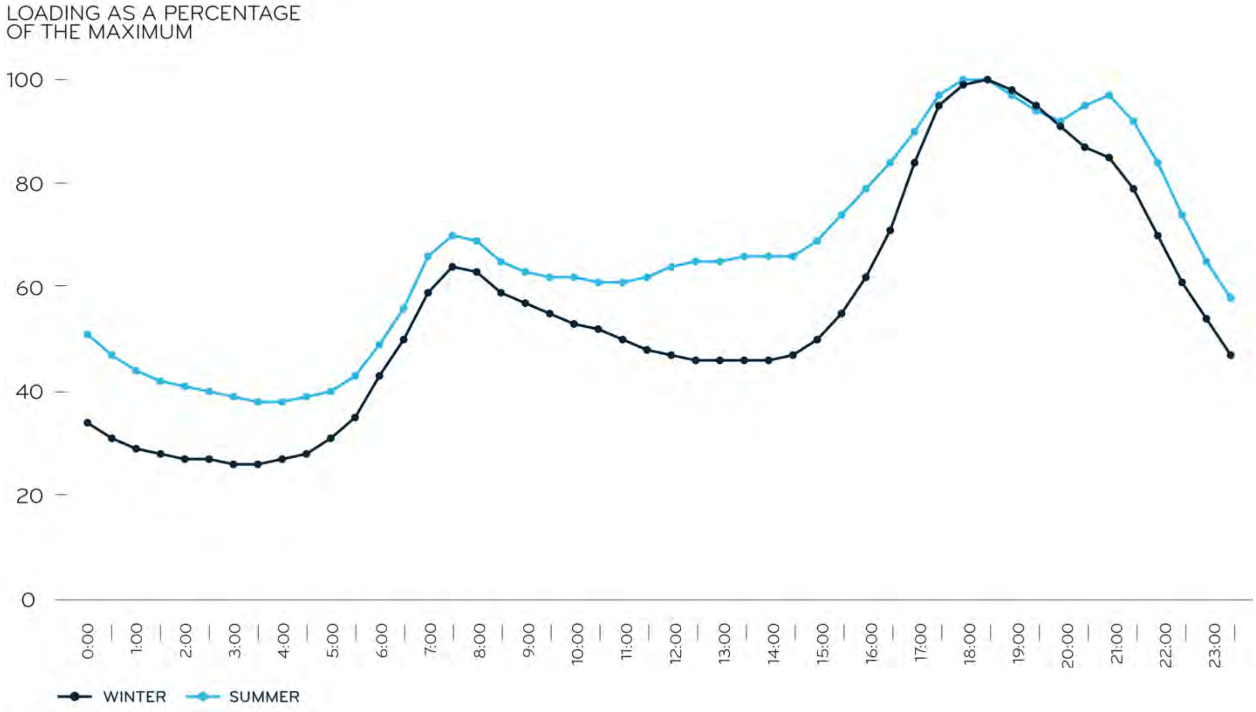


FIGURE 17.1: TYPICAL RESIDENTIAL DEMAND PROFILE (NORMALISED – LOADING AS A PERCENTAGE OF MAXIMUM)

The key characteristics of the residential demand profile are the distinct morning and evening peaks. There is a significant difference in demand between summer and winter profiles, where in absolute usage terms, winter is almost double that of summer. The profile characteristics are viewed at an 11 kV distribution feeder level rather than an individual customer profile

Capturing the profiles at this level in the network hierarchy shows a diversified demand profile illustrating the length of the evening winter peak which can extend upwards of three hours. There is no evidence of significant solar/PV in the summer profile which would show up as significantly reduced demand from late morning until late afternoon.

17.3.2 COMMERCIAL DEMAND PROFILE

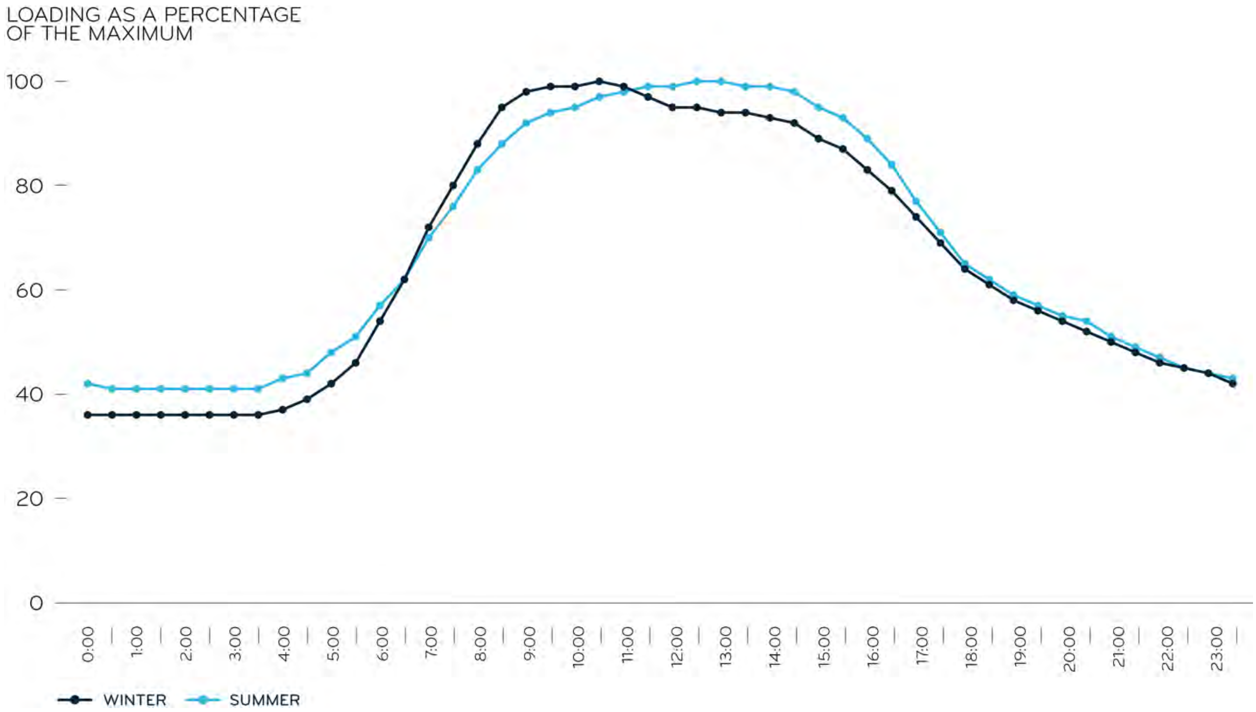


FIGURE 17.2: TYPICAL COMMERCIAL DEMAND PROFILE

Commercial demand follows a similar profile and loading for both winter and summer.

17.3.3 CBD DEMAND PROFILE

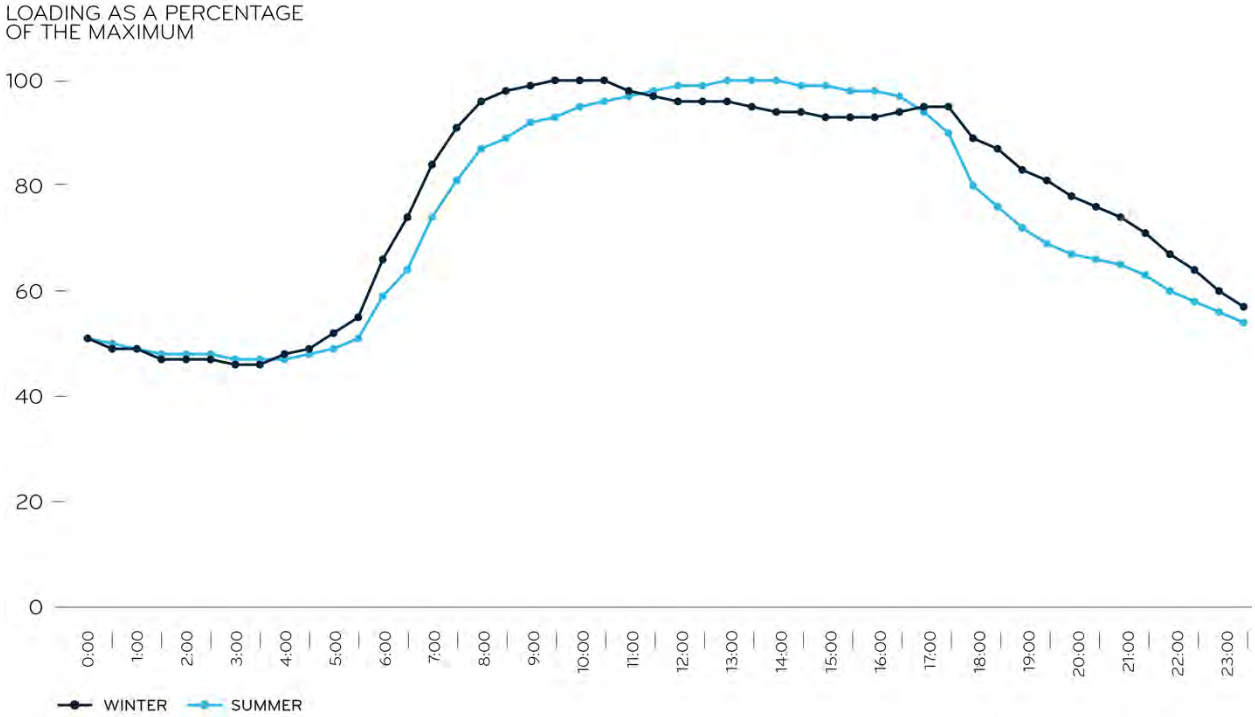


FIGURE 17.3: TYPICAL CBD DEMAND PROFILE

The Auckland CBD load is characterised by the summer profile where load rises quickly in the morning and drops off equally as rapidly in the evening. The winter load profile demonstrates a similar characteristic to the summer although more aggressive uptake before 7.00am and a slower ramp-down in the evenings. The peak load is summer driven mainly by air-conditioning, adding an extra 10% load above the winter demand profile.

17.3.4 LARGE CUSTOMERS THAT HAVE A SIGNIFICANT IMPACT ON THE NETWORK

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

- Fonterra at Lichfield;
- Auckland International Airport;
- Mangere Wastewater Treatment Plant;
- Bluescope Steel at Mangere;
- Pacific Steel at Mangere;
- Auckland Hospital at Newmarket;
- Carter Holt Harvey at Penrose
- Owens Illinois at Penrose

There has also been an increase in large customer queries supplied from Henderson and Silverdale GXPs..

17.4 Appendix 4 – AMP information disclosure compliance

17.4.1 INFORMATION DISCLOSURE DETERMINATION REQUIREMENT (EXISTING)

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
	Overview	
3.1.	A summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant;	Section 1.8
3.2.	Details of the background and objectives of the EDB's asset management and planning processes;	Sections: 5, 10
3.3.	A purpose statement which -	
3.3.1.	makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes;	Sections: 1.8, 5.1, 5.2
3.3.2.	states the corporate mission or vision as it relates to asset management;	Sections: 1.8, 5.1, 5.2
3.3.3.	identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB;	Section 5
3.3.4.	states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management; and	Section 5
3.3.5.	includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans; The purpose statement should be consistent with the EDB's vision and mission statements and show a clear recognition of stakeholder interest.	Sections: 1, 5
3.4.	Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed;	Section 1.8
3.5.	The date that it was approved by the directors;	Section 1.8
3.6.	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates -	
3.6.1.	how the interests of stakeholders are identified	Section 4.4
3.6.2.	what these interests are;	Sections: 4.5, 4.6
3.6.3.	how these interests are accommodated in asset management practices; and	Section 4.5
3.6.4.	how conflicting interests are managed;	Section 4.5
3.7.	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including -	Sections: 6.1, 6.2
3.7.1.	governance–a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors;	Sections: 6.1, 6.2
3.7.2.	executive–an indication of how the in-house asset management and planning organisation is structured; and	Sections: 6.1, 6.2
3.7.3.	field operations–an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used;	Sections: 6.1, 6.2
3.8.	All significant assumptions -	
3.8.1.	quantified where possible;	Sections 8 - 15
3.8.2.	clearly identified in a manner that makes their significance understandable to interested persons, including-	Sections 8 - 15
3.8.3.	a description of changes proposed where the information is not based on the EDB's existing business;	Sections 8 - 15

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
3.8.4.	the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	Sections: 1, 8 - 15
3.8.5.	the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b;	Appendix 13
3.9.	A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures;	Sections: 1, 15.6
3.10.	An overview of asset management strategy and delivery;	Section 5
3.11.	An overview of systems and information management data;	Sections: 5.5.4, 5.5.5, 6.6, 6.7
3.12.	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data;	Section 6.7.3
3.13.	A description of the processes used within the EDB for -	
3.13.1.	managing routine asset inspections and network maintenance;	Section 8
3.13.2.	planning and implementing network development projects; and	Sections: 9 -13
3.13.3.	measuring network performance;	Sections: 7.5, 7.6, 7.7
3.14.	An overview of asset management documentation, controls and review processes.	Section 5.5
3.15.	An overview of communication and participation processes;	Section 5.5.6
3.16.	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise; and	Compliant
3.17.	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination	Compliant
	Assets Covered	
4	The AMP must provide details of the assets covered, including-	
4.1.	a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	Section 3.1
4.1.1.	the region(s) covered;	Section 3.1
4.1.2.	identification of large consumers that have a significant impact on network operations or asset management priorities;	Sections: 9.3.3, 10, Appendix 3
4.1.3.	description of the load characteristics for different parts of the network;	Sections: 10, Appendix 3
4.1.4.	peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	Section 10.7
4.2.	A description of the network configuration, including-	
4.2.1.	identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	Sections: 3, 10.7, Appendix 9
4.2.2.	a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	Sections: 3, 10.7, Appendix 9
4.2.3.	a description of the distribution system, including the extent to which it is underground;	Section 3
4.2.4.	a brief description of the network's distribution substation arrangements;	Section 3
4.2.5.	a description of the low voltage network including the extent to which it is underground; and	Section 3

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
4.2.6.	an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	Section 12
4.3.	If sub-networks exist, the network configuration information referred to in clause 4.2 must be disclosed for each sub-network.	N/A
	Network assets by category	
4.4	The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1.	voltage levels;	Sections: 12.3-12.9
4.4.2.	description and quantity of assets;	Sections: 12.3-12.11
4.4.3.	age profiles; and	Sections: 12.3-12.11
4.4.4.	a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	Sections: 12.3-12.11
4.5.	The asset categories discussed in clause 4.4 should include at least the following-	
4.5.1.	the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii);	Section 12
4.5.2.	assets owned by the EDB but installed at bulk electricity supply points owned by others;	N/A
4.5.3.	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	Sections: 12.10.1, 12.10.2
4.5.4.	other generation plant owned by the EDB.	Sections: 12.10.1, 12.10.2
	Service Levels	
5.	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	Section 7
6.	Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Section 7.5
7.	Performance indicators for which targets have been defined in clause 5 should also include-	
7.1.	Consumer oriented indicators that preferably differentiate between different consumer types; and	Section 7.2
7.2.	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	Section 7.8
8.	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	Sections: 7.2, 7.4, 7.5, 7.6, 7.7
9.	Targets should be compared to historic values where available to provide context and scale to the reader.	Sections: 7.2, 7.4, 7.5, 7.6, 7.7
10.	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	Sections: 7, 15
	Network Development Planning	
11.	AMPs must provide a detailed description of network development plans, including–	
11.1.	A description of the planning criteria and assumptions for network development;	Section 10
11.2.	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	Sections: 10.3.3, 10.4

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
11.3.	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	Sections: 9, 10, 16
11.4.	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	Sections: 9, 10, 16
11.4.1.	the categories of assets and designs that are standardised; and	Sections: 9, 10, 16
11.4.2.	the approach used to identify standard designs;	Sections: 9, 10, 16
11.5.	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network;	Sections: 8 -13
11.6.	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network;	Section 10
11.7.	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision;	Section 10
11.8.	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	Section 10.4
11.8.1.	explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	Section 10.4
11.8.2.	provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	Section 10.7
11.8.3.	identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Section 10.7
11.8.4.	discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives;	Sections: 10.3.4, 10.3.5, 10.5, 10.7, 10a
11.9.	Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	Sections: 10.7, 10a
11.9.1.	the reasons for choosing a selected option for projects where decisions have been made;	Sections: 10.7, 10a
11.9.2.	the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; and	Sections: 10.7, 10a
11.9.3.	consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment;	Sections: 10.3.4, 10.3.5, 10.5, 10.7, 10a
11.10.	A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	
11.10.1.	a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	Section 10.7
11.10.2.	a summary description of the programmes and projects planned for the following four years (where known); and	Sections: 10.7, 10a
11.10.3.	an overview of the material projects being considered for the remainder of the AMP planning period;	Sections: 10.7, 10a
11.11.	A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated; and	Section 9.3.4
11.12.	A description of the EDB's policies on non-network solutions, including-	Sections: 10.3.4, 10.3.5, 10.5, 10.7, 10a

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
11.12.1.	economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	Sections: 10.3.4, 10.3.5, 10.5, 10.7, 10a
11.12.2.	the potential for non-network solutions to address network problems or constraints.	Sections: 10.3.4, 10.3.5, 10.5, 10.7, 10a
	Lifecycle Asset Management Planning (Maintenance and Renewal)	
12.	The AMP must provide a detailed description of the lifecycle asset management processes, including–	
12.1.	The key drivers for maintenance planning and assumptions;	Sections: 8, 12.3-12.11
12.2.	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Sections: 8, 12.3-12.11
12.2.1.	the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	Sections: 8, 12.3-12.11
12.2.2.	any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Sections: 8, 12.3-12.11
12.2.3.	budgets for maintenance activities broken down by asset category for the AMP planning period;	Sections: 8, 12.3-12.11
12.3.	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.3.1.	the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	Sections: 8, 12.3-12.11
12.3.2.	a description of innovations that have deferred asset replacements;	Sections: 12.10.1
12.3.3.	a description of the projects currently underway or planned for the next 12 months;	Section 12a
12.3.4.	a summary of the projects planned for the following four years (where known); and	Section 12a
12.3.5.	an overview of other work being considered for the remainder of the AMP planning period; and	Section 12a
12.4.	The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in clause 4.5.	Sections: 12, 12a
	Non-Network Development, Maintenance and Renewal	
13.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including–	
13.1.	a description of non-network assets;	Section 14.3
13.2.	development, maintenance and renewal policies that cover them;	Section 14.7
13.3.	a description of material capital expenditure projects (where known) planned for the next five years; and	Sections: 14.4-14.10
13.4.	a description of material maintenance and renewal projects (where known) planned for the next five years.	Sections: 14.6-14.8
	Risk Management	
14.	AMPs must provide details of risk policies, assessment, and mitigation, including–	
14.1.	Methods, details and conclusions of risk analysis;	Section 6.3
14.2.	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	Section 6.3
14.3.	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	Section 6.3
14.4.	Details of emergency response and contingency plans.	Section 6.4

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
15.	AMPs must provide details of performance measurement, evaluation, and improvement, including–	
15.1.	A review of progress against plan, both physical and financial;	Section 15
15.2.	An evaluation and comparison of actual service level performance against targeted performance;	Sections: 7.2, 7.4, 7.5, 7.6, 7.7
15.3.	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Sections: 5.5, Appendix 12
15.4.	An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Sections: 5.5, Appendix 12
	Capability to Deliver	
16.	AMPs must describe the processes used by the EDB to ensure that-	
16.1.	The AMP is realistic and the objectives set out in the plan can be achieved; and	Sections: 1, 16
16.2.	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Sections: 6, 16

17.4.2 INFORMATION DISCLOSURE DETERMINATION REQUIREMENT (TRANCHE 1)

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
	Planned / Unplanned Interruptions (Q1)	
17.1	A description of how the EDB provides notice to and communicates with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in this area;	Section 7.5.1
	Power Quality (Q2)	
17.2	A description of the EDB's practices for monitoring voltage, including -	
17.2.1	the EDB's practices for monitoring voltage quality on its low voltage network;	Section 7.3
17.2.2	work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	Section 7.3
17.2.3	how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder;	Section 7.3
17.2.4	how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and	Section 7.3
17.2.5	any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	Section 7.3
	Connecting New Customers and Altering Connections (Q3)	
17.4	A description of the EDB's practices for connecting consumers, including	
17.4.1	the EDB's approach to planning and management of (a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and (b) alterations to existing connections (offtake and injection connections);	Sections: 4.4, 4.5, 7.2
17.4.2	how the EDB is seeking to minimise the cost to consumers of new or altered connections;	Section 9.3
17.4.3	the EDB's approach to planning and managing communication with consumers about new or altered connections; and	Section 9.3
17.4.4	commonly encountered delays and potential timeframes for different connections.	Section 9..3

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
	Customer Complaints (Q4)	
17.3	A description of the EDB's customer service practices, including -	
17.3.1	the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services;	Sections: 4.4, 4.5, 7.2
	New Connection Impact to Network and Asset Management (D2)	
17.5	A description of the following:	
17.5.1	how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, e.g. the network location of new demand, generation, or storage capacity; and	Section 10.3.2
17.5.2	how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	Section 10.3.2
	Innovation (D4)	
17.6	Must include a description of the following -	
17.6.1	any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials;	Sections: 2, 4.3-4.5, 10
17.6.2	the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers;	Sections: 2, 4.3-4.5, 10
17.6.3	how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices;	Sections: 2, 4.3-4.5, 10
17.6.4	how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and	Sections: 2, 4.3-4.5, 10
17.6.5	the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	Sections: 2, 4.3-4.5, 10
	Vegetation Management (AM7A)	
12.6	Identification of vegetation management related maintenance. This must include an explanation of the approach and assumptions that the EDB uses to inform its vegetation management related maintenance.	Section 8
	Assumptions for Investment Forecasts (AM7B)	
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle asset management. This must include an explanation of -	
12.5.1	the approach that the EDB uses to inform its capital expenditure projections for lifecycle asset management; and	Sections: 10.4, 12.2, 15.6
12.5.2	the rationale for using the approach for each asset category.	Sections: 10.4, 12.2, 15.6
	Lifecycle Asset Management (AM8A)	
3.11.1	To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-	
3.11.1	(e) how asset management data informs the models that an EDB develops and uses to assess asset health;	Section 5.5.3
3.11.1	(f) how the outputs of these models are used in developing capital expenditure projections.	Section 5.5.3
	Non-Wire Alternatives (AM8B)	

CONTENTS OF THE AMP	CLAUSE	AMP SECTION
12.7	The EDB's consideration of non-network solutions to inform its capital and operational expenditure projections for lifecycle asset management. This must include an explanation of the approach and assumptions the EDB used to inform these expenditure projections;	Sections: 10.3.5, 10.4, 10.5

17.5 Appendix 5 – Significant changes from AMP2022

2023 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2022 AMP SCHEDULE DATE	REASON FOR CHANGE
FY25	Penrose	Penrose TIL Feeder	FY23	Change in customer requirement
On-hold	Manukau	Manukau Super Clinic Expansion	FY25	Change in customer requirement
FY24	South Howick	South Howick 33/11 kV Replace T1	FY28	Project brought forward to align with T2 replacement
FY24	Triangle Rd	Triangle 33/11 kV TX Replace T1	FY26	Project brought forward to align with T2 replacement
FY23	Takanini	Takanini 33/11 kV TX Replace T2	FY27	TX refurbed in FY23 due asset conditions
FY23	Takanini	Takanini 33/11 kV TX Replace T1	FY28	TX refurbed in FY23 due asset conditions
FY24	Waimauku	Waimauku 33 kV TX Replace T1	FY30	Project brought forward due to asset conditions
FY24	Pakuranga	Pakuranga 11 kV SWBD Replace	FY27	Project brought forward due to asset conditions
FY27	Onehunga	Onehunga SUBT Cable replace	FY31	Project brought forward due to asset conditions
FY23	Torbay	Torbay SUBT Cable replace	FY27	Project brought forward due to asset conditions
FY24	Birkdale	Birkdale (56) SUBT Cable replace	FY28	Project brought forward due to asset conditions
FY24	Manly	Manly (55B) SUBT Cable replace	FY30	Project brought forward due to asset conditions
Cancelled	Warkworth	Warkworth load control	FY24	Change in network solution
Beyond AMP horizon	Kumeu	Kumeu Zone Substation New	FY31	Deferred due to alternative solution
FY32	Mt Albert	Mt Albert Zone Substation capacity upgrade	Beyond AMP horizon	Updated load forecast
FY24	Tamaki	Tamaki land purchase for ZSS	FY26	Updated load forecast and security shortfall
FY24	Southdown	Southdown land purchase for ZSS	On-hold	Land opportunity is available
Beyond AMP horizon	Greenhithe	Greenhithe 33/11 kV 2nd TX	FY27	Updated load forecast
Beyond AMP horizon	Northcote	Northcote 33/11 kV 2nd TX	FY29	Updated load forecast
FY26	Swanson	Swanson 33/11 kV 2nd TX	FY30	Updated load forecast
FY29	Waikaukau	Waikaukau 33/11 kV 2nd TX	FY31	Updated load forecast
Beyond AMP horizon	Snells Beach	Snells Beach 33/11 kV 2nd TX	FY31	Deferred with alternative solution
FY30	Te Atatu	Te Atatu 33/11 kV T1+T2 TX capacity upgrade	FY32	Updated load forecast
FY32	Manly	Manly 33/11 kV TX capacity upgrade	Beyond AMP horizon	Updated load forecast
FY28	Brickworks	Brickworks 33/11 kV 2nd TX	Beyond AMP horizon	Updated load forecast
FY27	Belmont	Belmont 33/11 kV T1+T2 TX capacity upgrade	Beyond AMP horizon	Updated load forecast
FY28	Waimauku	Waimauku 33/11 kV T2 TX capacity upgrade	Beyond AMP horizon	Updated load forecast

2023 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2022 AMP SCHEDULE DATE	REASON FOR CHANGE
FY26	Riverhead	Riverhead 33/11 kV TX capacity upgrade	Beyond AMP horizon	Updated load forecast
FY24	Wellsford	Wellsford 33 kV SWBD ODID	FY29	Align with Warkworth cable project
FY25	Ngataringa Bay	Ngataringa Bay Direct Supply from Belmont ZSS	FY27	Align with customer requirement
FY26	Greenhithe	Albany to Greenhithe 110 kV to 33 kV SUBT OH conversion	FY24	Align with customer investment
Beyond AMP horizon	Bush road	Bush Rd 33 kV SUBT cable upgrade	FY27	Deferred due to alternative solution
Beyond AMP horizon	Hobsonville	Henderson to Hobsonville 33 kV 3rd SUBT cable new	FY27	Change in customer requirement
FY24	Warkworth	Wellsford ZSS to Warkworth 33 kV SUBT cable new	FY28	Change in network solution
Beyond AMP horizon	Hobsonville	Hobsonville to Kumeu 33 kV SUBT cable new	FY31	Change in network solution
Beyond AMP horizon	Henderson valley	Westgate To Henderson 33 kV 2nd SUBT cable new	FY31	Replaced by alternative solution
FY26	Maraetai	Maraetai Subtrans Reinforcement	Beyond AMP horizon	Brought forward due to updated load forecast
FY26	Waimauku	SH16 Huapai to Waimauku future proofing ducts	FY24	Align with timing of major road work project
Cancelled	Rosedale	Rosedale East Coast Rd 11 kV reinforcement	FY26	Replaced by alternative solution
FY29	St Johns	St Johns Pilkington Rd 11 kV feeders new (KO driven)	FY27	Align with third party development project
Beyond AMP horizon	Hobsonville	Trig Road 11 kV reinforcement	FY27	Deferred with alternative solution
Cancelled	Mangere East	Mangere East Station Rd 11 kV Reinforcement	FY29	Replaced by alternative solution
FY28	CBD	CBD Quay 11 kV to 22 kV conversion for security	FY31	Updated load forecast and security shortfall
Beyond AMP horizon	CBD	CBD Victoria 11 kV to 22 kV conversion for security	FY32	Updated load forecast and security shortfall
Cancelled	Takanini	Brookby 11 kV OH reinforcement	FY31	Replaced by alternative solution
FY25	Hobsonville	Data centre Hobsonville stage 2	-	New project
FY25	Hobsonville	Data centre Hobssonville AKL 05	-	New project
FY25	Silverdale	Data centre Silverdale AKL 03	-	New project
FY25	Manurewa	Spark Data centre Popes Rd Stage 2 11 kv Feeder Manurewa	-	New project
FY25	Papakura/Takanini	Fonterra Takanini two 11 kV Feeders	-	New project
FY27	Glenvar	East Coast Rd and Glenvar Rd	-	New project
FY26	Mt Albert	Mt Albert Carrington Road	-	New project
FY26	Takapuna	Takapuna Lake Rd and Esmonde Rd	-	New project
FY24	Warkworth	Wellsford ZSS to Warkworth 33 kV SUBT cable Stage 2	-	New project
FY29	Sandringham	Sandringham subtran upgrade	-	New project
FY24	Dairy Flat	Dairy Flat ZS Stage 1 subtrans cable	-	New project
FY30	Ranui	Ranui 2nd 33/11 kV TX & 11 kV switchgear	-	New project

2023 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2022 AMP SCHEDULE DATE	REASON FOR CHANGE
FY25	Sandspit	Sandspit Zone Substation New	-	New project
FY32	Chevalier	Chevalier subtran upgrade	-	New project
FY26	Dairy Flat	Dairy Flat ZS Stage 2 transformers and switchgear	-	New project
FY29	Dairy Flat	Dairy Flat ZS Stage 3 3rd transformer and subtrans circuits	-	New project
FY25	Greenhithe	Albany GXP Greenhithe New Subtrans Cable	-	New project
FY28	Rosedale	Albany GXP Rosedale Subtrans Cable Reinforcement	-	New project
FY24	Redhills	Henderson GXP Redhills Subtrans future-proofing ducts	-	New project
FY32	East Coast	East Coast 2nd 33/11 kV TX & 33 kV cable	-	New project
FY25	Rosedale	Rosedale Rd (Triton Dr to Tawa Dr) future-proofing ducts	-	New project
FY29	Onehunga	Onehunga 11 kV reinforcement for security in ONEH K02	-	New project
FY32	Te Papapa	Te Papapa 11 kV reinforcement for security in TPAP K12 and K17	-	New project
FY24	CBD	CBD 22 kV Extension Airedale St	-	New project
FY26	Tamaki	Reinforcement – GI Merton Rd & Apirana	-	New project
FY27	Mt Albert	Carrington Rd future-proofing ducts	-	New project
FY26	Hillsborough	Hillsborough 11 kV reinforcement to supply Carr Rd e-bus	-	New project
FY27	Quay	Quay new 22 kV feeders to supply Downtown e-ferry	-	New project
FY30	Quay	Onehunga new 11 kV feeders to supply Neilson St e-bus	-	New project
FY29	Hans	Hans Middlemore Cres 11 kV feeder new	-	New project
FY32	Otara	Otara Chapel Heights 11 kV feeder new	-	New project
FY27	Mangere Central	Mangere Central Robertson Rd 11 kV feeder new	-	New project
FY24	Mangere	Mangere E-Bus feeder	-	New project
FY27	Maraetai	Maraetai - Pine Harbour E-Ferry	-	New project
FY26	Highbury	Highbury k11 and k03 reinforcement for E-Ferry	-	New project
FY26	Ngataringa Bay	NGAT K01 & BELM K01 reinforcement for E-Ferry	-	New project
FY27	Gulf Harbour	GULF K13 & K07 reinforcement for E-Ferry	-	New project
FY28	Belmont	BELM K09 & K03 reinforcement for E-Ferry	-	New project
FY28	Rosedale	RDAL 11kV reinforcement/Dedicated feeder E-Bus	-	New project
FY24	Howick	Howick K05 11 kV feeder reinforcement /E-ferry	-	New project
FY28	Howick	Howick Bucklands Beach 11 kV feeder new	-	New project
FY24	Wiri West	West Wiri Southern Gateway 11 kV feeders	-	New project

2023 AMP SCHEDULE DATE	SUBSTATION	PROJECT AND PROGRAMME DESCRITPION	2022 AMP SCHEDULE DATE	REASON FOR CHANGE
FY24	Westgate	Fred Taylor Drive 11 kV reinforcement	-	New project
FY28	Manurewa	Manurewa Alfriston Rd 11 kV feeder new	-	New project
FY26	Takanini	Takanini Heb Place 11 kV feeder new E-Bus	-	New project
FY26	Takanini	Takanini ZSS capacity upgrade	-	New project
FY25	Belmont	Belmont 33/11 kV T3	-	New project
FY24	Quay	CBD 22 kV extension Emily Place	-	New project

17.6 Appendix 6 – Forecast Capital Expenditure (Schedule 11a)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

sch ref

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
11a(i): Expenditure on Assets Forecast	**$000 (in nominal dollars)**										
Consumer connection	131,097	156,797	166,925	125,107	110,948	101,788	101,167	103,505	100,473	100,747	102,762
System growth	45,777	103,324	109,635	110,797	87,114	118,853	117,395	113,347	129,290	129,652	111,743
Asset replacement and renewal	153,632	159,879	107,199	155,990	160,742	153,580	144,957	141,344	144,866	140,127	145,300
Asset relocations	26,021	34,593	40,693	40,474	43,299	42,202	42,100	42,942	43,801	44,677	45,570
Reliability, safety and environment:											
Quality of supply	53	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	173	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	5,410	25,161	45,690	81,261	90,180	89,181	87,404	87,801	88,983	89,585	90,175
Total reliability, safety and environment	5,636	25,161	45,690	81,261	90,180	89,181	87,404	87,801	88,983	89,585	90,175
Expenditure on network assets	362,163	479,754	470,142	513,629	492,283	505,604	493,023	488,939	507,413	504,788	495,550
Expenditure on non-network assets	46,462	54,603	42,216	47,218	45,557	36,747	33,460	30,227	34,716	36,127	39,905
Expenditure on assets	408,625	534,357	512,358	560,847	537,840	542,351	526,483	519,166	542,129	540,915	535,455
plus Cost of financing	6,955	10,423	10,753	11,970	11,288	11,905	11,614	11,420	12,129	12,169	11,760
less Value of capital contributions	169,473	236,827	288,988	290,062	296,100	256,211	236,760	237,431	249,009	255,229	260,764
plus Value of vested assets											
Capital expenditure forecast	246,107	307,953	234,123	282,755	253,028	298,045	301,337	293,155	305,249	297,855	286,451
Assets commissioned	197,214	404,979	214,302	259,775	242,772	294,308	301,818	292,175	304,747	297,853	286,451

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
	$000 (in constant prices)										
Consumer connection	131,097	145,252	146,226	105,104	90,009	80,958	78,887	79,127	75,303	74,028	74,028
System growth	45,777	95,716	96,040	93,082	70,673	94,531	91,541	86,651	96,901	95,267	80,498
Asset replacement and renewal	153,632	148,107	93,906	131,049	130,405	122,152	113,033	108,054	108,575	102,964	104,672
Asset relocations	26,021	32,046	35,647	34,003	35,127	33,566	32,828	32,828	32,828	32,828	32,828
Reliability, safety and environment:											
Quality of supply	53	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	173	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	5,410	23,308	40,024	68,268	73,160	70,931	68,155	67,122	66,692	65,826	64,961
Total reliability, safety and environment	5,636	23,308	40,024	68,268	73,160	70,931	68,155	67,122	66,692	65,826	64,961
Expenditure on network assets	362,163	444,429	411,843	431,506	399,374	402,138	384,444	373,782	380,299	370,913	356,987
Expenditure on non-network assets	46,462	50,582	36,981	39,668	36,959	29,227	26,091	23,108	26,019	26,546	28,747
Expenditure on assets	408,625	495,011	448,824	471,174	436,333	431,365	410,535	396,890	406,318	397,459	385,734
Subcomponents of expenditure on assets (where known)											
Energy efficiency and demand side management, reduction of energy losses											
Overhead to underground conversion	10,600	12,296	12,188	12,188	12,188	12,188	12,188	12,188	12,188	12,188	12,188
Research and development	-	-	-	-	-	-	-	-	-	-	-
Cybersecurity (Commission only)											

Difference between nominal and constant price forecasts

for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28	CY+6 31 Mar 29	CY+7 31 Mar 30	CY+8 31 Mar 31	CY+9 31 Mar 32	CY+10 31 Mar 33
	$000										
Consumer connection	-	11,545	20,699	20,003	20,939	20,830	22,280	24,378	25,170	26,719	28,734
System growth	-	7,608	13,595	17,715	16,441	24,322	25,854	26,696	32,389	34,385	31,245
Asset replacement and renewal	-	11,772	13,293	24,941	30,337	31,428	31,924	33,290	36,291	37,163	40,628
Asset relocations	-	2,547	5,046	6,471	8,172	8,636	9,272	10,114	10,973	11,849	12,742
Reliability, safety and environment:											
Quality of supply	-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	1,853	5,666	12,993	17,020	18,250	19,249	20,679	22,291	23,759	25,214
Total reliability, safety and environment	-	1,853	5,666	12,993	17,020	18,250	19,249	20,679	22,291	23,759	25,214
Expenditure on network assets	-	35,325	58,299	82,123	92,909	103,466	108,579	115,157	127,114	133,875	138,563
Expenditure on non-network assets	-	4,021	5,235	7,550	8,598	7,520	7,369	7,119	8,697	9,581	11,158
Expenditure on assets	-	39,346	63,534	89,673	101,507	110,986	115,948	122,276	135,811	143,456	149,721

11a(ii): Consumer Connection

for year ended		Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	*Consumer types defined by EDB**	$000 (in constant prices)					
	Service Connection	26,110	22,582	22,840	21,188	20,444	20,859
	Customer Substations	38,497	76,098	82,176	46,503	33,583	23,408
	Business subdivisions	1,450	1,246	1,156	1,085	1,071	1,071
	Residential Subdivisions	58,429	40,739	35,793	32,207	30,811	31,520
	Capacity Changes	5,826	3,173	2,982	2,842	2,821	2,821
	Street Lighting	785	1,414	1,279	1,279	1,279	1,279
	Easements	-	-	-	-	-	-
	**include additional rows if needed*						
	Consumer connection expenditure	131,097	145,252	146,226	105,104	90,009	80,958
less	Capital contributions funding consumer connection	133,104	147,477	148,467	106,714	91,387	82,198
	Consumer connection less capital contributions	(2,007)	(2,225)	(2,241)	(1,610)	(1,378)	(1,240)

11a(iii): System Growth

		Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
	Subtransmission	12,490	19,722	11,992	16,431	5,048	6,282
	Zone substations	15,997	29,375	42,461	38,737	29,519	42,711
	Distribution and LV lines	2,346	1,892	1,472	2,500	3,205	3,480
	Distribution and LV cables	10,331	43,336	39,541	34,419	31,031	39,563
	Distribution substations and transformers	3,188	703	-	-	-	-
	Distribution switchgear	553	-	-	-	-	-
	Other network assets	872	688	574	995	1,870	2,495
	System growth expenditure	45,777	95,716	96,040	93,082	70,673	94,531
less	Capital contributions funding system growth	21,637	53,722	82,867	116,799	129,657	104,333
	System growth less capital contributions	24,140	41,994	13,173	(23,717)	(58,984)	(9,802)

11a(iv): Asset Replacement and Renewal

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
		$000 (in constant prices)					
Subtransmission		4,178	11,598	7,024	24,782	20,303	10,182
Zone substations		34,140	36,553	14,350	29,002	32,152	35,510
Distribution and LV lines		22,412	17,307	10,157	10,055	10,067	9,952
Distribution and LV cables		46,819	45,007	34,322	36,359	37,341	36,507
Distribution substations and transformers		21,449	21,592	6,733	6,628	6,636	6,443
Distribution switchgear		14,458	8,631	16,209	18,512	18,522	18,308
Other network assets		10,176	7,419	5,111	5,711	5,384	5,250
Asset replacement and renewal expenditure		153,632	148,107	93,906	131,049	130,405	122,152
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		153,632	148,107	93,906	131,049	130,405	122,152

11a(v): Asset Relocations

*Project or programme**	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
		$000 (in constant prices)					
Overground to underground conversions		10,600	12,296	12,188	12,188	12,188	12,188
**include additional rows if needed*							
All other project or programmes - asset relocations		15,421	19,750	23,459	21,815	22,939	21,378
Asset relocations expenditure		26,021	32,046	35,647	34,003	35,127	33,566
less Capital contributions funding asset relocations		14,732	18,190	21,819	20,171	19,172	17,250
Asset relocations less capital contributions		11,289	13,856	13,828	13,832	15,955	16,316

11a(vi): Quality of Supply

*Project or programme**	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - quality of supply		53					
Quality of supply expenditure		53	-	-	-	-	-
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		53	-	-	-	-	-

11a(vii): Legislative and Regulatory

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - legislative and regulatory		173					
Legislative and regulatory expenditure		173	-	-	-	-	-
less Capital contributions funding legislative and regulatory							
Legislative and regulatory less capital contributions		173	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
*Project or programme**		$000 (in constant prices)					
All other projects or programmes - other reliability, safety and environment		5,410	23,308	40,024	68,268	73,160	70,931
Other reliability, safety and environment expenditure		5,410	23,308	40,024	68,268	73,160	70,931
less Capital contributions funding other reliability, safety and environment							
Other reliability, safety and environment less capital contributions		5,410	23,308	40,024	68,268	73,160	70,931

11a(ix): Non-Network Assets

	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
Routine expenditure							
*Project or programme**		$000 (in constant prices)					
**include additional rows if needed*							
All other projects or programmes - routine expenditure		22,969	22,143	14,801	18,730	15,263	15,736
Routine expenditure		22,969	22,143	14,801	18,730	15,263	15,736
Atypical expenditure							
*Project or programme**							
**include additional rows if needed*							
All other projects or programmes - atypical expenditure		23,493	28,439	22,180	20,938	21,696	13,491
Atypical expenditure		23,493	28,439	22,180	20,938	21,696	13,491
Expenditure on non-network assets		46,462	50,582	36,981	39,668	36,959	29,227

17.7 Appendix 7 – Forecast Operational Expenditure (Schedule 11b)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	15,402	16,087	16,683	17,196	17,737	18,245	18,755	19,279	19,819	20,374	20,944
11	Vegetation management	5,632	5,667	5,861	7,261	7,844	8,006	8,166	8,330	8,496	8,666	8,839
12	Routine and corrective maintenance and inspection	20,924	22,637	23,605	26,430	26,078	26,180	26,551	26,950	30,533	28,597	29,474
13	Asset replacement and renewal	12,368	15,876	17,025	17,045	14,254	13,267	13,525	13,389	13,594	13,978	14,372
14	**Network Opex**	54,326	60,267	63,174	67,933	65,914	65,697	66,997	67,948	72,443	71,614	73,630
15	System operations and network support	45,289	52,084	55,204	57,333	59,278	60,944	62,664	64,806	66,930	68,909	71,082
16	Business support	44,458	48,324	50,102	51,577	52,903	54,126	55,352	56,618	57,925	59,276	60,673
17	**Non-network opex**	89,746	100,408	105,306	108,910	112,180	115,070	118,017	121,424	124,855	128,185	131,755
18	**Operational expenditure**	144,072	160,675	168,480	176,843	178,094	180,767	185,013	189,372	197,298	199,799	205,385
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32	31 Mar 33
21		$000 (in constant prices)										
22	Service interruptions and emergencies	15,402	15,607	15,657	15,706	15,828	15,951	16,076	16,201	16,328	16,456	16,585
23	Vegetation management	5,632	5,500	5,500	6,625	7,000	7,000	7,000	7,000	7,000	7,000	7,000
24	Routine and corrective maintenance and inspection	20,924	21,953	22,155	24,126	23,280	22,889	22,760	22,649	25,144	23,113	23,335
25	Asset replacement and renewal	12,368	15,387	15,978	15,570	12,735	11,601	11,593	11,253	11,200	11,290	11,381
26	**Network Opex**	54,326	58,447	59,290	62,027	58,843	57,441	57,429	57,104	59,672	57,859	58,301
27	System operations and network support	45,289	50,512	51,805	52,362	52,896	53,284	53,713	54,458	55,141	55,659	56,288
28	Business support	44,458	46,894	47,017	47,107	47,209	47,323	47,447	47,580	47,724	47,879	48,047
29	**Non-network opex**	89,746	97,407	98,822	99,469	100,105	100,607	101,160	102,038	102,865	103,538	104,334
30	**Operational expenditure**	144,072	155,854	158,112	161,497	158,949	158,048	158,588	159,142	162,537	161,397	162,636
31	**Subcomponents of operational expenditure (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
32												
33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	4,098	4,467	4,863	5,281	5,735	6,230	6,773	7,368	8,021	8,737	9,523
37	Cybersecurity (Commission only)											
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
Difference between nominal and real forecasts	$000										
Service interruptions and emergencies	-	480	1,026	1,491	1,909	2,293	2,679	3,078	3,491	3,917	4,359
Vegetation management	-	167	361	636	844	1,006	1,166	1,330	1,496	1,666	1,839
Routine and corrective maintenance and inspection	-	683	1,451	2,303	2,798	3,291	3,791	4,302	5,389	5,484	6,139
Asset replacement and renewal	-	489	1,047	1,475	1,519	1,666	1,932	2,135	2,394	2,688	2,991
Network Opex	-	1,820	3,885	5,905	7,070	8,256	9,568	10,845	12,771	13,755	15,329
System operations and network support	-	1,572	3,399	4,971	6,381	7,660	8,951	10,348	11,789	13,250	14,794
Business support	-	1,429	3,084	4,470	5,694	6,803	7,906	9,038	10,201	11,397	12,626
Non-network opex	-	3,001	6,483	9,441	12,075	14,463	16,857	19,386	21,990	24,647	27,421
Operational expenditure	-	4,821	10,368	15,346	19,145	22,719	26,425	30,231	34,761	38,402	42,750

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.

17.8 Appendix 8 – Asset Condition (Schedule 12a)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

sch ref													
7					Asset condition at start of planning period (percentage of units by grade)								
8													% of asset forecast to be replaced in next 5 years
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)		
10	All	Overhead Line	Concrete poles / steel structure	No.	0.00%	0.10%	21.28%	32.74%	45.87%		4		6.33%
11	All	Overhead Line	Wood poles	No.	-	1.64%	83.12%	8.92%	6.31%		4		33.28%
12	All	Overhead Line	Other pole types	No.	-	-	5.20%	0.91%	93.89%		4		-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	89.61%	7.41%	2.98%		3		-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	72.35%	25.70%	1.95%		3		-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	1.45%	4.42%	39.28%	54.84%		2		4.66%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	97.23%	2.77%		2		-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-		N/A		
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	32.51%	49.41%	16.20%	1.87%		2		82.05%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	85.69%	14.31%		2		-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	92.83%	7.17%		2		-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A		
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A		
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	97.39%	2.61%	-		2		-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	7.76%	70.69%	21.55%		4		1.72%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	33.33%	66.67%		4		-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	1.03%	11.00%	13.06%	74.91%		3		1.03%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	6.42%	52.29%	29.36%	11.93%		3		22.02%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A		
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	5.10%	81.53%	10.19%	3.18%		3		24.20%
30	HV	Zone substation switchgear	33kV RMU	No.	-	16.67%	33.33%	33.33%	16.67%		3		16.67%
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	40.91%	59.09%		3		-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	100.00%	-	-		3		-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	10.31%	24.31%	13.65%	51.74%		3		11.58%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A		
35													

36												
37					Asset condition at start of planning period (percentage of units by grade)							
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	11.06%	42.92%	19.47%	26.55%		4	7.08%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	0.76%	84.37%	12.05%	2.83%		3	1.21%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.44%	0.23%	1.96%	17.45%	79.93%		2	0.66%
44	HV	Distribution Cable	Distribution UG PILC	km	0.26%	1.17%	3.85%	76.30%	18.42%		2	1.43%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	86.19%	13.81%	-		2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.89%	-	6.51%	47.93%	44.67%		4	11.36%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	10.90%	9.04%	80.05%		4	3.72%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.65%	0.70%	43.40%	20.90%	33.35%		4	9.13%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	3.63%	5.28%	68.92%	15.79%	6.37%		3	16.55%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.11%	2.38%	39.89%	16.13%	39.50%		3	6.63%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.11%	7.13%	42.25%	25.63%	23.89%		3	9.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	5.42%	2.11%	32.73%	27.81%	31.93%		3	7.53%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	33.33%	66.67%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2.06%	1.60%	75.01%	7.89%	13.44%		4	3.65%
55	LV	LV Line	LV OH Conductor	km	-	-	86.37%	7.53%	6.10%		3	0.23%
56	LV	LV Cable	LV UG Cable	km	0.45%	5.43%	19.99%	36.82%	37.31%		2	5.88%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km						100.00%	1	
58	LV	Connections	OH/UG consumer service connections	No.						100.00%	1	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	0.77%	59.50%	19.14%	20.58%		3	0.77%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	3.77%	38.44%	36.43%	21.36%		4	3.77%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	73.85%	20.00%	6.15%		3	6.15%
62	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-		4	-
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km	-	-	8.62%	-	91.38%		4	-

17.9 Appendix 9 – Forecast Capacity (Schedule 12b)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Atkinson Road	18	21	N-1	38	85%	21	90%	No constraint within +5 years	Meets Vector security criteria
10	Auckland Airport	13	25	N-1	-	54%	25	63%	No constraint within +5 years	Meets Vector security criteria
11	Avondale	29	24	N-1 switched	24	120%	24	135%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
12	Bairds	24	24	N-1	22	98%	24	103%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
13	Balmain	9	-	N-1 switched	24	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
14	Balmoral	15	24	N-1	13	61%	24	70%	No constraint within +5 years	Meets Vector security criteria
15	Belmont	14	14	N-1	22	97%	14	121%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
16	Birkdale	22	24	N-1	22	93%	24	96%	No constraint within +5 years	Meets Vector security criteria
17	Brickworks	11	-	N-1 switched	25	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and planned 2nd transformer
18	Browns Bay	16	16	N-1	37	98%	16	105%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
19	Bush Road	22	23	N-1	17	98%	23	99%	No constraint within +5 years	Meets Vector security criteria
20	Carbine	13	22	N-1	9	62%	22	64%	No constraint within +5 years	Meets Vector security criteria
21	Chevalier	22	19	N-1 switched	14	115%	24	96%	No constraint within +5 years	Capacity to be increased by subtransmission circuit replacement
22	Clendon	21	24	N-1	13	89%	24	104%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
23	Clevedon	2	-	N-1 switched	3	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup, Counties backup and Kawakawa Bay BESS
24	Coatesville	11	-	N-1 switched	17	-	12	95%	No constraint within +5 years	Meets Vector security criteria on completion of 2nd transformer project (FY23)
25	Drive	24	24	N-1 switched	25	101%	24	124%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup.
26	East Coast Road	18	-	N-1 switched	35	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
27	East Tamaki	15	24	N-1	6	64%	24	85%	No constraint within +5 years	Meets Vector security criteria
28	Flatbush	21	24	N-1	11	87%	24	99%	No constraint within +5 years	Meets Vector security criteria
29	Forrest Hill	16	16	N-1 switched	32	101%	16	105%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
30	Freemans Bay	17	22	N-1	15	79%	22	95%	No constraint within +5 years	Meets Vector security criteria

31		Glen Innes	12	24	N-1	13	50%	24	71%	No constraint within +5 years	Meets Vector security criteria
32		Greenhithe	11	-	N	9	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
33		Greenmount	41	48	N-1	27	85%	48	89%	No constraint within +5 years	Meets Vector security criteria
34		Gulf Harbour	9	-	N-1 switched	10	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
35		Hans	24	24	N-1 switched	11	100%	24	106%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
36		Hauraki	6	-	N-1 switched	32	-	-		No constraint within +5 years	Meets Vector security criteria
37		Helensville	11	9	N-1 switched	39	124%	9	134%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and South Head Diesel generator
38		Henderson Valley	16	15	N-1 switched	50	106%	15	119%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and Piha Diesel generator
39		Highbrook	10	21	N-1	-	45%	21	47%	No constraint within +5 years	Meets Vector security criteria
40		Highbury	13	-	N-1 switched	23	-	16	107%	No constraint within +5 years	Constraint relieved by the installation of the second transformer
41		Hillcrest	25	24	N-1 switched	52	105%	24	117%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
42		Hillsborough	17	24	N-1	17	70%	24	81%	No constraint within +5 years	Meets Vector security criteria
43		Hobson 110/11kV	12	55	N-1	7	21%	55	28%	No constraint within +5 years	Meets Vector security criteria
44		Hobson 22/11kV	15	68	N-1	7	22%	68	24%	No constraint within +5 years	Meets Vector security criteria
45		Hobson 22kV	48	140	N-1	30	35%	140	48%	No constraint within +5 years	Meets Vector security criteria
46		Hobsonville	15	15	N-1	41	98%	15	147%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
47		Hobsonville Point	16	20	N-1	24	81%	20	211%	No constraint within +5 years	New Whenuapai ZSS will offload Hobsonsonville Point to meet
48		Howick	41	48	N-1	15	85%	48	88%	No constraint within +5 years	Meets Vector security criteria
49		James Street	19	15	N-1 switched	39	124%	15	131%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
50		Kaukapakapa	6	-	N-1 switched	28	-	-		No constraint within +5 years	Meets Vector security criteria
51		Keeling Road	17	20	N-1	-	88%	20	88%	No constraint within +5 years	Meets Vector security criteria
52		Kingsland	24	24	N-1 switched	20	101%	24	115%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
53		Laingholm	9	9	N-1 switched	30	102%	9	105%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
54		Lichfield	16	20	N-1	-	80%	20	80%	No constraint within +5 years	Meets Vector security criteria
55		Liverpool	24	48	N-1	22	50%	48	80%	No constraint within +5 years	Meets Vector security criteria
56		Liverpool 22kV	76	247	N-1	41	31%	247	47%	No constraint within +5 years	Meets Vector security criteria
57		Mangere Central	33	48	N-1	16	68%	48	73%	No constraint within +5 years	Meets Vector security criteria
58		Mangere East	26	24	N-1 switched	24	110%	24	122%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
59		Mangere West	19	30	N-1	4	63%	30	95%	No constraint within +5 years	Meets Vector security criteria
60		Manly	20	14	N-1 switched	26	139%	14	146%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
61		Manukau	31	48	N-1	26	65%	48	71%	No constraint within +5 years	Meets Vector security criteria
62		Manurewa	41	48	N-1	36	86%	48	99%	No constraint within +5 years	Meets Vector security criteria
63		Maraetai	9	18	N-1	5	52%	18	57%	No constraint within +5 years	Meets Vector security criteria
64		McKinnon	19	24	N-1	55	80%	24	115%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
65		Mcleod Road	9	-	N-1 switched	29	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
66		McNab	38	48	N-1	23	79%	48	81%	No constraint within +5 years	Meets Vector security criteria
67		Milford	7	-	N-1 switched	26	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
68		Mt Albert	7	-	N	7	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
69		Mt Wellington	16	24	N-1	18	65%	24	87%	No constraint within +5 years	Meets Vector security criteria

70		New Lynn	14	14	N-1	25	99%	14	114%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
71		Newmarket	39	48	N-1	32	80%	48	84%	No constraint within +5 years	Meets Vector security criteria
72		Newton	19	19	N-1 switched	18	102%	19	139%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
73		Ngataringa Bay	8	-	N	7	-	-		No constraint within +5 years	Constraint relieved by the installation of 3rd Belmont transformer and 11kV cable reinforcement
74		Northcote	6	-	N-1 switched	21	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
75		Onehunga	15	15	N-1	16	99%	24	78%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and sub-transmission reinforcement
76		Orakei	22	22	N-1 switched	15	102%	22	114%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
77		Oratia	5	-	N-1 switched	23	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
78		Orewa	20	22	N-1	30	87%	22	111%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
79		Otara	27	36	N-1	24	76%	36	83%	No constraint within +5 years	Meets Vector security criteria
80		Pacific Steel	19	44	N-1	-	43%	44	43%	No constraint within +5 years	Meets Vector security criteria
81		Pakuranga	22	24	N-1	11	92%	24	91%	No constraint within +5 years	Meets Vector security criteria
82		Papakura	27	23	N-1 switched	10	117%	23	127%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
83		Parnell	13	18	N-1	12	72%	18	90%	No constraint within +5 years	Meets Vector security criteria
84		Ponsonby	16	14	N-1 switched	9	110%	14	111%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
85		Quay	18	24	N-1	14	75%	24	93%	No constraint within +5 years	Meets Vector security criteria
86		Quay 22kV	42	120	N-1	29	35%	120	44%	No constraint within +5 years	Meets Vector security criteria
87		Ranui	15	-	N-1 switched	46	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and planned 2nd transformer
88		Red Beach	22	23	N-1	27	96%	23	126%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
89		Remuera	27	24	N-1 switched	22	111%	24	117%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
90		Riverhead	13	9	N-1 switched	21	141%	9	215%	No constraint within +5 years	Meets Vector security criteria due to planned transformer upgrades and cable reinforcement
91		Rockfield	21	24	N-1	26	89%	24	92%	No constraint within +5 years	Meets Vector security criteria
92		Rosebank	22	22	N-1	11	100%	22	113%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
93		Rosedale	15	24	N-1	28	63%	24	110%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
94		Sabulite Road	21	14	N-1 switched	37	151%	14	160%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
95		Sandringham	21	24	N-1	19	89%	24	126%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
96		Simpson Road	5	-	N-1 switched	20	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
97		Snells Beach	8	-	N-1 switched	13	-	-		No constraint within +5 years	Constraint relieved by the BESS and new Sandspit Zone Substation
98		South Howick	24	18	N-1 switched	14	132%	18	116%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup

99		Spur Road	13	24	N-1	41	56%	24	73%	No constraint within +5 years	Meets Vector security criteria
100		St Heliers	22	21	N-1 switched	20	105%	21	108%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
101		St Johns	21	24	N-1	16	89%	24	101%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
102		Sunset Road	14	14	N-1 switched	27	101%	14	110%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
103		Swanson	11	-	N-1 switched	23	-	13	108%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and planned 2nd transformer
104		Sylvia Park	16	24	N-1	10	67%	24	73%	No constraint within +5 years	Meets Vector security criteria
105		Takanini	20	18	N-1 switched	18	109%	18	171%	Other	Individual feeder constraint relieved by new feeders
106		Takapuna	8	-	N-1 switched	16	-	20	50%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and planned 2nd transformer (FY23)
107		Te Atatu	22	14	N-1 switched	24	159%	14	168%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and transformer upgrades
108		Te Papapa	21	24	N-1	15	86%	24	86%	No constraint within +5 years	Meets Vector security criteria
109		Torbay	9	-	N-1 switched	18	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
110		Triangle Road	16	12	N-1 switched	42	133%	12	135%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
111		Victoria	16	22	N-1	13	71%	22	88%	No constraint within +5 years	Meets Vector security criteria
112		Waiake	9	-	N-1 switched	29	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
113		Waiheke	13	15	N-1	-	84%	15	89%	No constraint within +5 years	Meets Vector security criteria
114		Waikaukau	8	-	N-1 switched	13	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
115		Waimauku	13	-	N-1 switched	19	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backupn and planned transformer replacements
116		Wairau Road	19	16	N-1 switched	43	118%	16	137%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
117		Warkworth	23	18	N-1 switched	37	128%	18	113%	No constraint within +5 years	Constraint relieved by the Omaha substation and demand response project
118		Wellsford	8	9	N-1	20	90%	9	98%	No constraint within +5 years	Meets Vector security criteria
119		Westfield	24	24	N-1	24	100%	24	120%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
120		Westgate	16	24	N-1	32	67%	24	133%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup and future Red Hill ZSS
121		White Swan	29	32	N-1	24	89%	32	121%	No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup
122		Wiri	43	43	N-1	22	100%	43	124%	No constraint within +5 years	Future Constraint relieved by new feeders and West Wiri zone substation
123		Woodford	9	-	N-1 switched	30	-	-		No constraint within +5 years	Meets Vector security criteria due to sufficient 11kV backup with 11kV reinforcement project

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

17.10 Appendix 10 – Forecast Network Demand (Schedule 12c)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

sch ref									
7	**12c(i): Consumer Connections**								
8	*Number of ICPs connected in year by consumer type*					**Number of connections**			
9				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10			for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
11		*Consumer types defined by EDB**							
12		Residential & Small Medium Enterprise (SME)		15,065	14,101	13,381	12,373	12,142	12,544
13		Industrial & Commercial		225	167	167	172	172	172
14									
15									
16									
17	**Connections total**			15,290	14,268	13,548	12,545	12,314	12,716
18		**include additional rows if needed*							
19									
20									
21									
22	**Distributed generation**			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23		Number of connections made in year		1,301	839	839	839	839	839
24		Capacity of distributed generation installed in year (MVA)		10	6	6	6	6	6
25	**12c(ii) System Demand**								
26				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
28		GXP demand		1,760	1,882	1,997	2,060	2,121	2,230
29	*plus*	Distributed generation output at HV and above		16	16	16	16	16	16
30	**Maximum coincident system demand**			1,776	1,898	2,013	2,076	2,137	2,246
31	*less*	Net transfers to (from) other EDBs at HV and above							
32	**Demand on system for supply to consumers' connection points**			1,776	1,898	2,013	2,076	2,137	2,246
33	**Electricity volumes carried (GWh)**								
34		Electricity supplied from GXPs		8,636	8,631	9,082	9,193	9,303	9,475
35	*less*	Electricity exports to GXPs							
36	*plus*	Electricity supplied from distributed generation		144	144	144	144	144	144
37	*less*	Net electricity supplied to (from) other EDBs							
38	**Electricity entering system for supply to ICPs**			8,780	8,775	9,226	9,337	9,447	9,620
39	*less*	Total energy delivered to ICPs		8,426	8,417	8,860	8,966	9,072	9,238
40	**Losses**			353	358	366	371	375	382
41									
42	**Load factor**			56%	53%	52%	51%	50%	49%
43	**Loss ratio**			4.0%	4.1%	4.0%	4.0%	4.0%	4.0%
44									

17.11 Appendix 11 – Forecast Interruptions and Duration (Schedule 12d)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Vector Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	117.1	117.1	117.1	117.1	117.1	117.1
12	Class C (unplanned interruptions on the network)	104.8	104.8	104.8	104.8	104.8	104.8
13	**SAIFI**						
14	Class B (planned interruptions on the network)	2.88	2.88	2.88	2.88	2.88	2.88
15	Class C (unplanned interruptions on the network)	1.34	1.34	1.34	1.34	1.34	1.34

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Southern Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	50.4	50.4	50.4	50.4	50.4	50.4
12	Class C (unplanned interruptions on the network)	48.9	48.9	48.9	48.9	48.9	48.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.50	1.50	1.50	1.50	1.50	1.50
15	Class C (unplanned interruptions on the network)	0.64	0.64	0.64	0.64	0.64	0.64

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Northern Network**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

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

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8								
9		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		66.7	66.7	66.7	66.7	66.7	66.7
12	Class C (unplanned interruptions on the network)		56.0	56.0	56.0	56.0	56.0	56.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		1.38	1.38	1.38	1.38	1.38	1.38
15	Class C (unplanned interruptions on the network)		0.69	0.69	0.69	0.69	0.69	0.69

17.12 Appendix 12 – Asset Management Maturity (Schedule 13)

Company Name	**Vector Limited**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Vector's Asset Management Policy has been reviewed in February 2023, authorised by our Chief Operating Officer - Electricity, Gas, Fibre and Chief Executive Officer. The document is part of the controlled document management system and reviewed periodically.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	Good asset management is practiced implicitly based on the policies and strategies which are approved by Vector's Board. The Board also approves the asset management plans and associated budget.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Asset header class (asset fleet) strategies have been prepared and reviewed for all primary asset classes. Lifecycle cost and service implications are adequately considered in maintenance and replacement decisions. Asset strategies are reviewed on an annual basis. This is an ongoing program of work with the opportunity to improve and integrate the results with Vector's Condition Based Asset Risk Management (CBARM) models.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.

Question No.	Function	Question			User Guidance	Why	Who	Record/documented Information
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Asset management plans (AMP) are documented, implemented and maintained with alignment to asset management strategies and cover all asset life cycle activities (documented in the form of header class strategies, standards covering planning, design, equipment selection, operation, maintenance, inspection, testing and decommissioning.)		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The AMP is communicated to all stakeholders including employees and Field Service Providers (FSPs). The organisation, end to end process, Vector's Delegated Financial Authorities (DFA) and works programmes are all set up to deliver the works effectively. The AMP is also published on the Vector web site. Project Governance meetings are held every two weeks to ensure effective delivery of the AMP.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The AMP outlines the key roles responsible for its delivery. Vector's delegated authorities framework and policy, and position descriptions for each role further define the roles and authorities. Key tasks and responsibilities are allocated to team members who report on progress against plan on a monthly basis.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3.5	The AMP is physically delivered by our Field Service Providers for both Capex projects and Opex works. Capex delivery of works is governed by a staged gate process that is defined in detail. A project can only move to the next stage gate once the actions for a specific stage-gate is completed. Works are competitively tendered in accordance with standard contract arrangements including NZS3910. For large programs of works the workload are split between a larger panel of service providers to ensure a workload balance		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3.5	Our response to emergency situations, e.g., extreme weather events, natural disasters and similar is governed by our operational document, the Emergency Response Guide. This guide sets the scene for responses, reactions and actions. During an emergency event a specific response group will be assigned with tasks to and for each member. The group will meet daily until the contingency plan is in place and during the contingency. Reviews of pending risks or pending events are conducted fortnightly during which action plans are reviewed, renewed and/or closed		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3.5	Overall responsibility to deliver the AMP rests with the Chief Operating Officer, Electricity, Gas and Fibre. The Chief Engineer together with the General Managers of the Network Performance Team, Capital Programme Delivery Team, Customer Excellence Team and Commercial Strategy, report to the COO. Each GM is assigned the appropriate authority to deliver a certain part(s) of the asset management plan in accordance with the asset management policy. The AMP is delivered by our panel of external field service providers in terms of contractual agreements and arrangements and they understand their roles in the delivery of the asset management strategy, its objectives and plans		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3.5	A dedicated team is in place to compile the annual asset management plan. Each member is assigned his/her part of the AMP to be compiled, arrange for its review to publishing. A dedicated team exists to assess network risk, compile scopes of work and/or programmes of work to address the risk and then after the works have been delivered, review the residual risks. Two dedicated teams schedule and program the delivery of capex works and maintenance works respectively. A dedicated Supply Team has been setup for the planning of long lead items, establishment of umbrella agreements and other procurement arrangements. A Governance Group has been setup that meets weekly to discuss the delivery of the asset management plan, risks, delays and action plans. Agreements are in place for external specialist consultancies to provide advice		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Service Levels and KPI's are set and monitored across the organisation through readily accessible dashboards. In addition, monthly reporting, quarterly team updates and strong engagement with programme delivery and service providers ensure that there is a strong focus on the delivery of asset management requirements. Weekly update sessions are held to convey network events, network reliability targets and specific project updates and challenges. "All Hands" sessions have been introduced quarterly to convey the asset management objectives to the wider EGF team		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3.5	Maintenance standards, design standards and planning standards are in place for Vector and its service providers to guide the delivery of the asset management plan. Standards are controlled, changed and improved via a strict and well-defined change control process that involves our field service providers in the formal review and approval process. A strict as-building regime is in place to ensure works are delivered, checked and recorded in accordance with our standards. The recording of faults is done via clear guidance in our maintenance standards and network fault information collected and recorded in our software application for this purpose. Its corrective actions and outcomes are checked and controlled via this software app. A team of dedicated field assessors provide assurance by means of inspections in the field against the standards. A full time standards engineer is in place to record proposed improvements to standards and then arrange for their change controlled reviews, updates, revisioning and publishing. This person also reviews requests for deviations, their approval or rejection.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	Core competencies required to undertake asset management activities are identified by our HR department in the job design process. Such requirements are determined and defined in conjunction with asset managers and included in Vector's job profiles-position descriptions. Our HR in-house training division has a suite of formal learning modules to increase knowledge of our requirements to develop and improve asset management capability. We also have a formal engineering progression scheme in place that encourages employees to develop their skills. Regular inspections of worksites is a requirement to hone asset management skills and ensure contact with the real world asset environment		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3.5	Our competency requirements (worker type competency - WTC) are clearly defined for different roles and responsibilities to achieve our asset management plan. Record is kept of the competency training of Vector employees and training refreshers are scheduled as necessary to ensure WTC competency compliance and currency. For our FSPs, we conduct random audits of their competency compliance and check that competencies are maintained in their internal database. Vector also maintains an internal database of the competencies of our internal staff as well as our FSP qualified personnel. Under our letters of authorisation to access our network, all FSPs and contractors have a legal obligation to maintain competency currencies.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	For our FSPs, we conduct random audits of their competency compliance and check that competencies are maintained in their internal database. Vector also maintains an internal database of the competencies of our internal staff as well as our FSP qualified personnel. Under our letters of authorisation to access our network, all FSPs and contractors have a legal obligation to maintain competency currencies.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3.5	A group meeting is held every Wednesday in which the SAIDI and SAIFI performance of the network is presented and discussed. Network risks, incidents and asset management challenges are also presented and discussed. Asset management information is conveyed to other stakeholders via their involvement in the control of update and improvement of standards. Asset management information and asset performance information are presented in detailed and comprehensive dashboards and daily fault reports. Our planning standards are available on our website for external parties and the same applies for the connection of distributed generation. Monthly operational meetings are held with our FSPs where progress, risks and challenges against targets, are discussed and actions agreed. Short update meetings are held every second day for more granular updates on specific programmes and projects. Under contingency or emergency scenarios specific teams are setup and daily meetings are scheduled for the duration of such events. Specific network instructions are issued to FSPs via a numbered and controlled formal instruction in which FSPs are required to acknowledge receipt.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2.5	Vector's Controlled Document Management standard, USD001, defines asset management documents and sets out the hierarchy of documentation for our asset management plan. This standard also sets out in detail how changes to documents are to be managed, as well as the change control, approval and acceptance process. Our Asset Management Plan (AMP) is communicated to our Board and internal stakeholders and is available to external parties via our web portal. Our AMP is shared widely with our FSPs. Supporting the asset management plan and its objectives is a comprehensive set of design, maintenance and operating standards. The latest copies are held in our Information portal. We have made good progress with our asset management framework that describes the overarching requirements for asset management system.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3.5	Vector's primary information systems of record supporting Asset Management are SAP-PM, GE Small World GIS, and the Data Analytics platform. Collectively these systems capture, manage and allow the use of data for asset management decision making. In order to ensure that these systems contain the data necessary to support asset management, Vector has the following processes in place. A set of data standards have been developed governing the asset master data required to be captured in GIS and SAP-PM. These standards define the asset data model, which are based upon (and aligned to) Vector's asset and maintenance standards. A set of data standards have been developed for planned, corrective and reactive maintenance data capture. The data standards are based upon Vector's maintenance standards and define in detail the data to be captured in the field when performing the respective forms of maintenance. The systems of record have been designed and built based upon these two sets of data standards. Change management processes exist to ensure changes to maintenance standards or asset standards (including the introduction of new asset types) flow into the data standards and respective system of record. The data analytics platform has been developed to facilitate improved reporting and analysis of data, and also to develop complex analytical models, providing deeper insights into asset management not available or apparent from the raw data.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Vector has implemented a number of steps to ensure the data contained in SAP-PM and GE Small World GIS are consistent, accurate and of requisite quality. Data standards are in place for the capture of data. This includes asset master data, spatial data, connectivity, and maintenance data. Systems of record (SAP-PM and GIS) have been developed to align to these data standards. Data validation routines exist in all systems, based up data standards, to ensure all data captured conforms to the defined data standards. Service levels are in place for data updaters to ensure data is captured according to the defined standards and in a timely fashion. System automation and integration has been developed to reduce manual data capture wherever possible.Vector has established an Asset Information Team responsible for ensuring the data and systems are curated and continually improved, and ensure that the data standards are adhered to. Independent data quality assurance testing is conducted on key data sets.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Vector has a number of processed in place to ensure the Asset Information System remains relevant to its needs. Asset information systems are a core aspect of the wider Asset Management System. A key element of this is the alignment of asset standards and maintenance standards with data standards and system or record. An established Asset Information Team is responsible for ensuring the data and systems are curated and continually improved. Data quality improvement programmes are funded to address legacy data issues and make improvements to data. A change management process is in place to ensure all changes to asset standards and maintenance standards are flowed through into the system of record and associate data capture and maintenance standards. Innovation projects are run to develop new data sets to support and optimise asset management. A data analytics platform has been implemented to improve access to data in a consistent and integrated fashion. Condition based risk models and CBARM models have been developed using the analytical platform, to inform and improve asset decision making with regard to asset management replacement and refurbishment programs and projects.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3.5	A dedicated Risk Assessment team is in place in Vector. They investigate, assess, evaluate and document incidents and make recommendations for the asset management of such assets. Each incident investigation report is numbered, registered, stored and issued for action, information and learning. Risks are recorded in our risk recording application known as ARM (active risk manager). Vector also records the failure modes and effects analysis (FMEA), action plans and target dates to address risks across the asset lifecycle. Regular meetings are held to address, assess and record progress with regard to risks. The networks risk management process is defined in standard UCD001, which states how risks are managed		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	The outcomes of risk and incidents are recorded and a formal and numbered network instruction issued to our FSPs where training and/or a change in asset management process is required. We also work with our equipment suppliers, training facility and FSPs to setup up training sessions on the use of specific equipment to reduce the risk of failure. In some instances, risks and incidents will require a change in procurement standards, planning standards and/or operational standards. Such recommendations will be made in our Active Risk Management system and/or incident reports and will be followed up under our change control system		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Our Active Risk Management are operated and updated by our Risk Assessment team but falls under the governance of our corporate risk manager who is assisted by our corporate legal team to assess such risks that require legal, regulatory or statutory assessment. If and where necessary for risks that require regulatory, statutory and/or legal input are registered in the corporate risk register and governed by a change control process in which risk owners are required to update progress and provide asset management plans to manage such risks. Vector is also subject to annual NZS 7901 public safety audits during which the network is physically inspected and issues and actions recorded.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Our asset management plan for the acquisition, creation and enhancement of assets is done in accordance with a circular lifecycle asset management process underpinned by suites of standards and operational instructions. The life cycle process is initiated by a recorded network risk that is assessed and scored, a needs statement is established that is converted into a monetized asset management item, included into the asset management plan, a scope is compiled and the works are physically delivered. Where a new type of asset is to be introduced it will be via a formal asset introduction process that goes through a formal change control that involves our field service providers. As and where necessary this will include field trials. The consideration of climate change and carbon footprint form an important part of this process. Enhanced assets are recorded in our regulated asset base and formal drawing repository application and handed over for maintenance and acceptance via a formal process		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	Our suite of maintenance standards is very specific and clear in their requirements for the recording of asset condition data for all our asset classes. The recording of asset condition data is done via field handheld tables by our field service providers via our SAP software. This uses a so-called SAP-PM application in which defects, their severity and corrective actions are recorded and immediately updated. This SAP-PM software application also records the corrective actions and costs for corrective actions and provides a quick and efficient overview of costs, remaining risks, remaining activities and performance. Our SAP-PM is closely aligned with the requirements of our maintenance standards		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	Our detailed maintenance standards form the basis for the condition and performance of our assets. Asset are inspected in accordance with the requirements of our maintenance standards under a planned maintenance regime. The conditions and performance of our assets are recorded by our field service providers in our SAP-PM application and further corrective actions undertaken as required. For our asset replacement and enhancement programmes and projects we have adopted condition based asset risk models to inform our works		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Asset related failures, incidents and emergency situations are recorded in incident reports complete with recommendations and actions. Incident reports are registered, numbered and stored in a Sharepoint repository. Risks, corrective actions and responsibility assignments are stated in our asset risk management application (ARM) and followed up with regular meetings. Where specific actions and responses are required by our field service providers, numbered and registered network instructions are used to our FSPs. They have to acknowledge receipt. Progress is checked during the monthly operational meetings with our FSPs and/or the second daily update meetings		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	The asset management plan is reviewed annually, and full updates are undertaken every second year. For our design and maintenance standards we have a full-time person that manages the continuous improvement of standards, their change control process and formal publishing. Each document has a current date and proposed review date which is governed automatically by the change control Sharepoint site settings. For our capital works asset management process we have in place a stage-gate process that clearly demarcates the actions and gates that need to be achieved before works can progress. Risks and actions are recorded in minutes of meeting and risk registers for each capital works project that can be audited post works completion under the lessons learnt stage		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	The first step in assessing poor performance and non-conformance is an assessment by the Risk Incident Team, relevant asset specialists and if required the Principal Engineer Asset Standards and Quality. The works will involve forensic analysis if and where necessary. If a product is found to not comply with our requirements, the supplier will be informed and instructed to take corrective actions. In extreme cases continued use of a product will be halted. If the non-performance is delivery related a meeting will be held with the field service provider in which corrective actions will be conveyed and formally recorded. Training will be provided if necessary		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.5	The premise to address an asset is underpinned by the network risk that it poses, its performance in the field and its cost to maintain versus the cost to replace or refurbish. Where it is clear that continued maintenance will result in undue and persistent maintenance costs, i.e. high whole lifecycle costs, replacement will be selected. Whether or not, the asset presents a health and safety risk to personnel, or the public will also inform whether an asset will be replaced or its maintenance continued. If asset replacement is selected the selection will undergo a rigorous options analysis and safety in design reviews underpinned by detailed cost estimates. If necessary, NPV calculations will be undertaken		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	The performance of the network is a driver to explore new technologies to improve the performance of the network. For this purpose, the Vector Asset specialists will liaise with equipment suppliers and other electricity lines businesses to explore the use of other technologies and products. Tests will be undertaken to check the viability of such technologies. Where necessary trials will be instigated and formally recorded by our Asset Standards and Quality engineer and if the trial proves successful the asset will be formally introduced for use in the network. This introduction of the asset will involve our field service providers via a change control process. Vector also participates in a number of international and Australia-NZ working groups to identify new asset management technologies and practices		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

17.13 Appendix 13 – Mandatory explanatory notes on forecast information (Schedule 14a)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory - EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.8.

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

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

BOX 1: COMMENTARY ON DIFFERENCE BETWEEN NOMINAL AND CONSTANT PRICE CAPITAL EXPENDITURE FORECASTS

Vector has used the capital expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2020. We have used a forecast of the Capital Goods Price Index (CGPI) as the inflator.

The CGPI forecast reduces from 10.45% in FY23 to 2.00% in FY28 and is stable thereafter. The forecast is based on CGPI observed to December 2022 with an assumed decline profile that is comparable to the declines observed in PPI.

The constant price capital expenditure forecast is inflated by the above-mentioned index to convert to a nominal price capital expenditure forecast.

Commentary on the difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

BOX 2: COMMENTARY ON DIFFERENCE BETWEEN NOMINAL AND CONSTANT PRICE OPERATIONAL EXPENDITURE FORECASTS

Vector has used the operational expenditure inflator based on the model used by the Commerce Commission in its DPP price reset on 1 April 2020. We have used an inflator which is a mix of the Producer Price Index (PPI) and the Labour Cost Index (LCI). The weighting between PPI (40%) and LCI (60%) is as per the Commission's model.

Vector has used the NZIER (New Zealand Institute of Economic Research) December 2022 PPI (Producer Price Index-inputs) and LCI (Labour Cost Index) forecasts up to March 2027. Thereafter, we have assumed a long-term inflation rate of 2.0% for both metrics.

The constant price operational expenditure forecast is inflated by the above-mentioned index to convert to a nominal price operational expenditure forecast.

17.14 Appendix 14 - Schedule 17 Certification for year-beginning disclosures

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Bruce Turner, and Paul Hutchison, being directors of Vector Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Vector Limited prepared for the purposes of clauses 2.6.1, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been prepared on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c, 12d and 13 are based on objective and reasonable assumptions which both align with Vector Limited's corporate vision and strategy and are documented in retained records.

Director

Director

12 May 2023

Date

vector

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