Firstlight network®

Asset Managment Plan

2023

Letter from the Chief Executive

Welcome to the Firstlight Network 2023 Asset Management Plan ("**AMP**"). Firstgas Group acquired Eastland Network Limited on 31 March and looks forward to continuing to support Tairāwhiti and Wairoa through its effective stewardship of the assets.

As we look to the future, there are three emerging themes that our asset management work needs to respond to—these are enhancing resilience, responding to the energy transformation, and balancing the energy trilemma. In this AMP, we have increased our focus on resilience, updated our work on our response to the energy transformation, and shared how we are thinking about balancing affordability, security, and sustainability over the long term.

During RY2023, extreme weather had a significant impact on the network. The weather events included ex-tropical cyclone Hale and cyclone Gabrielle. Most of the network performed very well; however, the infrastructure was severely damaged in some areas, and our network was no exception. Due to the damage to roading and our network, it took us more than two weeks to restore supply to a few isolated customers following the cyclones. We have enhanced our resilience strategy in response to the increasing incidence of extreme weather. The strategy outlined in this AMP is just our first step and will be expanded further in the 2024 AMP.

In the 2022 AMP, we accelerated the replacement of our wood pole fleet. This work was impacted by the response to the extreme weather we experienced; however, we could still replace around 3% of the fleet. During Cyclone Gabrielle, we experienced wind speeds that likely exceeded historical overhead line design limits. We have further accelerated our wood pole replacement program and plan to replace 20% of the fleet over the next five years.

We continue to monitor how the energy transformation is evolving. To date, we have not seen a material increase in electrification demand or installation of solar PV and batteries. We have forecast this to increase over the coming decades. Presently, the only material risk we see is related to the electrification of process heat. This could result in a step-change increase in demand that are difficult to forecast. Should this occur, additional investment in the network would be required.

Our forecast capital and operational expenditure have increased. Most of the increase in capital expenditure is for the renewal of our overhead assets, dealing with geohazards on the 110kV line that supply Gisborne and Wairoa, and refurbishment our aging fleet of generators, which were used to keep the lights on to communities during the recent extreme weather. The impact of inflation on the cost of doing work has also driven some of the increase; for some projects, the costs have escalated by more than 20%. The increase in operational expenditure reflects the higher cost of responding to extreme weather, managing vegetation and inspecting the network as our assets age.

We are aware of the impact that increasing expenditure has on future prices. In this AMP, we have introduced the energy trilemma and how we seek to balance supply security, enabling decarbonisation and energy affordability. We are committed to balancing these factors in a way that improves network resilience and supports our climate change objectives whilst keeping price increases as low as possible. This will require us to implement innovative and practical solutions that will meet our community's needs.

Responding to the extreme weather events took significant effort and diverted most of our staff and contract field resources onto response and recovery efforts for many months. I'd like to thank the team for their significant efforts during 2022/2023 and the Commerce Commission for the additional time granted to publish this plan.

Kind regards

Paul Goodeve
Chief Executive
Firstgas Group

Content

1. Executive Summary

1.1 Preamble to this Asset Management Plan

Firstgas Group acquired Eastland Network Limited on 31 March 2023 and subsequently changed the business's name to Firstlight Network Limited.

Following the national state of emergency and the significant impact of cyclone Gabrielle on the Firstlight Network from 12 to 20 February 2023, the Commerce Commission (the Regulator) approved a request for an extension to the publication of this asset management plan on 2 October 2023.

Notwithstanding the extension to the delivery date for this AMP, this report covers 1 April 2022 through 31 March 2023. Given the significant impact of ex-tropical cyclone Hale and cyclone Gabrielle on our network, we have enhanced the focus on resilience in this plan.

1.2 Introduction to Firstlight Network

Firstlight owns the electricity distribution assets that supply Gisborne, Wairoa and the East Coast. Firstlight owns and maintains the substations, poles, conductor and underground cabling that connect customers to the national transmission grid. Energy retailers use our network to supply customers with electricity.

Firstlight is 100% owned by the owners of the Firstgas Group of companies.

Following the acquisition, the core network operations of Eastland Network have been integrated within the Firstgas Group. Firstlight is now supported by the wider Firstgas Group, which has increased the capabilities of the Firstlight business.

Firstgas Group's vision is to *proudly leading the delivery of New Zealand's energy needs in a changing world*, and the group's mission is to *safely and reliably delivering energy that is affordable and acceptable to New Zealand's families and businesses*. These statements guide our management of the Firstlight network.

Preparation of the AMP is the responsibility of Firstlight's Senior Asset Planner, who reports to the Manager, Project Delivery and Asset Management within the Firstgas Group. The Firstlight operations, engineering, asset information, and commercial teams provide significant input into preparing the AMP.

1.3 About this AMP

1.3.1 How this plan is structured

This AMP focuses on the key issues facing the network, the strategy in response to those issues, and the development and lifecycle plans needed to achieve that strategy.

The AMP and this executive summary are set out in three parts:

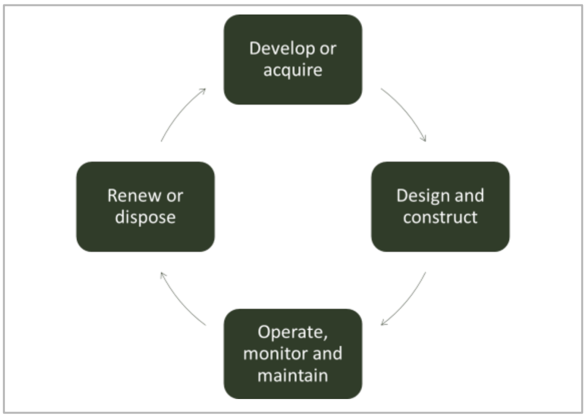
- Factors shaping policy and strategy;
- Asset management policy and strategy;
- Implementation of the asset management policy and strategy.

1.3.2 The approach to asset lifecycle management

This plan adopts a generally accepted asset lifecycle, as shown in Figure 1 below. The four stages of the asset lifecycle are:

- The *develop or acquire* phase, which covers the creation of an asset through development or acquisition and includes the identification of the need, evaluating options, undertaking conceptual design work, and preparing the preliminary business case (if the scale of the project warrants this)
- The *design and construct* phase covers the detailed design, tendering, the project business case and approval, project management, construction, and commissioning of new assets. The design phase has taken on increasing importance over the last decade as it is the phase where material risks can be engineered out through good design
- The *operate, monitor and maintain* phase covers the operation of the assets, ongoing inspection and testing, corrective and preventative maintenance, and any emergency response in relation to the assets. This is a key focus of fleet lifecycle plans.
- The *renew or dispose* phase covers deciding when to renew and/or dispose of assets. Typically, the decision to renew an asset is made in response to asset health, reliability, safety, obsolescence, and economic factors.

Figure 1: Phases of the asset lifecycle



References to each of these stages in this AMP are included in Section 2.6.

1.3.3 Planning period

This plan covers the ten years from 1 April 2023 to 31 March 2033 (regulatory years 2024 to 2033).

1.4 Factors shaping the Asset Management Policy and Strategy

A range of factors are shaping the asset management policy and strategy and, ultimately, how we manage the network. The most important of these are:

- Our historical focus on minimising distribution prices;
- The configuration of the network and the use of alternatives to lines to deliver security at the least cost;
- The economies of scale benefits from Firstgas Group;
- The aging of our subtransmission and distribution assets;
- The increasing impact of climate change on extreme weather events;
- The increasing pace of energy transformation and the potential for capacity constraints;
- There is a need to communicate how we intend to balance the energy trilemma;
- Our recent customer service performance;
- The impact of cyclone Gabrielle;
- Our recent reliability challenges.

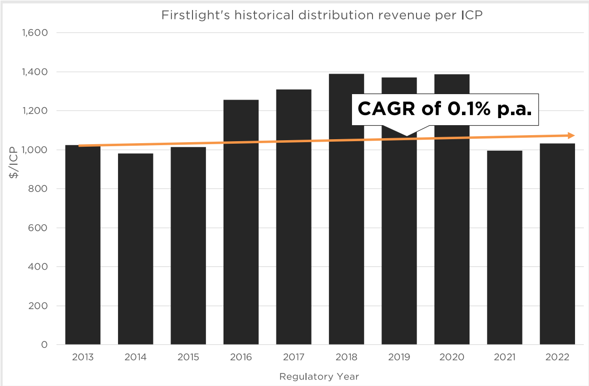
These factors and other issues are further detailed in Sections 3, 4 and 6 of this plan.

1.4.1 Our historical focus on minimising distribution prices

Firstlight has sought to minimise its investment in assets and operating costs to keep costs to customers as low as possible. This has been successful, and Firstlight has achieved a compounding annual growth rate (**CAGR**) for distribution costs per customer of 0.1% p.a. over the past ten years (refer to Figure 2).

Along with the region's geography and the location of communities, this focus has shaped how the network is configured and operated.

Figure 2: Historical average distribution price (Source: IDs)



1.4.2 The configuration of the network and the use of alternatives to lines to deliver security at the least cost

Firstlight's network supplies the townships of Gisborne and Wairoa and the remotely populated region of the East Coast. The dispersed nature of the network means that 89% of the network consists of overhead lines, of which 85% are located in rural or remote rural areas.

Due to the high number of small load centres, the network has relatively low levels of traditional subtransmission and zone substation security. It would be costly to provide security by having redundancy in subtransmission lines and zone substation transformers. Instead, we have provided appropriate network security using lower-cost generation alternatives.

All network 11kV distribution feeders are configured radially. Reclosers and sectionalisers are installed to minimise the impact of outages on rural feeders.

Firstlight is increasing the number of generators, sectionalisers and reclosers to minimise the impact of outages on its customers.

1.4.3 Economies of scope of Firstgas Group

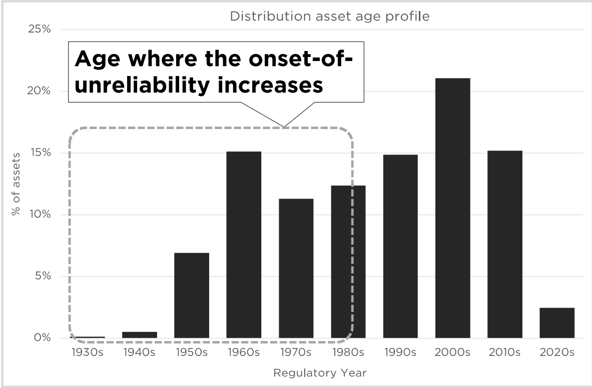
Firstlight Network and its customers benefit significantly from the economies of scale from its association with Firstgas Group. Firstgas Group owns and manages a diverse set of subsidiary assets, including gas transmission and distribution networks, property assets and other associated asset companies. This creates a significant pool of shared resources at the executive and corporate levels. This is detailed further in Sections 2.4 and 4.6.

1.4.4 The aging of our subtransmission and distribution assets

Large portions of our network were installed in the 1960s, 1970s and 1980s. These assets are now reaching a point in their lifecycle when there is an increasing risk of failure due to end-of-life issues that must be managed.

The ageing asset fleet has not resulted in high failure rates (as discussed in Section 6.5). However, managing the ageing asset fleet is a key focus for the business and a key driver of the increasing capital expenditure on the network.

Figure 3: Distribution Asset Age Profile (Source: 2022 IDs)

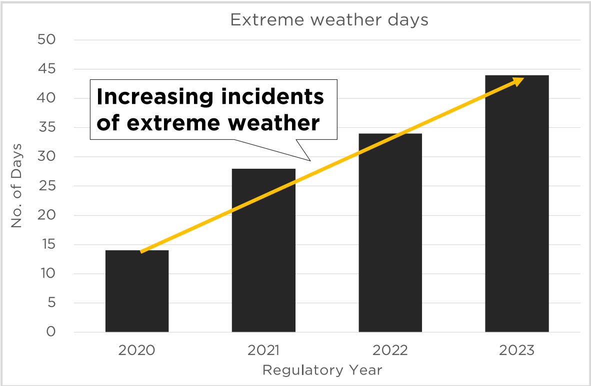


1.4.5 The increasing impact of climate change on extreme weather events

Our region has had multiple severe weather events throughout 2022/2023. The impact was not just on the Firstlight Network but across all infrastructure and highlighted the need for resilient energy systems.

The extreme weather significantly increased damage to the network by trees that are well outside the normal trimming zone. Due to regulatory constraints, it is difficult to maintain a suitable line corridor to prevent this type of damage.

Figure 4: Extreme Weather Days (Source: Metservice)



During cyclones, high winds damaged overhead lines. The windspeeds experienced during cyclone Gabrielle were very close to the design limit for modern overhead lines and were likely beyond the limits of older parts of the network that were designed to older (and lower) standards.

We have commenced work on how to improve the resilience of the network—in a cost-effective way.

1.4.6 The increasing pace of energy transformation and the potential for capacity constraints

The pace of energy transformation is increasing due to the improving economics of new technology and in response to climate change. The energy transformation will involve an increase in the charging of electric vehicles, the installation of solar PV and batteries, and the electrification of process heat and general heating.

While we do not have a large industrial customer base, some of these customers could significantly increase their electricity use should they shift from fossil fuels.

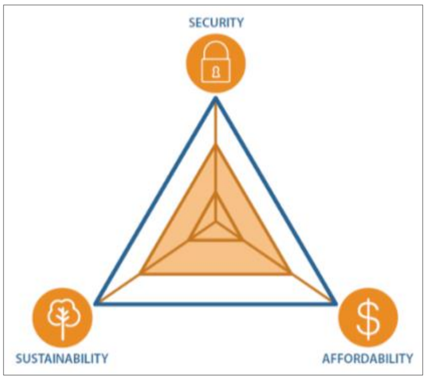
The direction outlined in the Climate Change Commission's report (and by other commentators) is more aggressive than we have factored into the demand and consumption forecasts included in this AMP, as we anticipate that electrification will lag behind the larger centres in the country. Our annual customer survey has confirmed this. However, the pace of electrification is constantly evolving; we regularly review our modelling assumptions to reflect the trends experienced on the network.

The 110kV lines supplying Gisborne are rated at 55.5MW, with current net peak demand close to 50.5MW[1]. The current spare capacity is sufficient for organic growth but insufficient for large new industrial loads and the electrification of transport and process heat over the medium term. We are currently progressing with a staged network upgrade and will look at other alternatives to provide capacity increases that may be needed. This matter is detailed in Section 10.

1.4.7 Communicate how we intend to balance the energy trilemma

The Energy Trilemma[2] is a well-recognised framework (refer to Figure 5) for strategic optimisation in the energy sector. This framework has been adopted throughout the energy sector to communicate how these factors are balanced.

Figure 5: The energy trilemma



The importance of this balance has increased for Firstlight due to the growing need for higher opex and capex to respond to our aging asset fleet, improve resilience, and support the electrification of transport and process heat.

We believe that it is important to communicate and consult with stakeholders about how we are thinking about balancing the energy trilemma and what this could mean for our customers.

Section 7.5 discusses how we are thinking about balancing these factors.

1.4.8 Our recent customer service performance

In late 2022, we undertook our annual customer survey. The survey indicated that we are performing well concerning reliability but less so in relation to pricing and communication.

Customers agreed that *keeping the power on*, *restoring power quickly when an outage occurs*, and *keeping prices low* is important to them. They ranked reliability as more important than maintaining low prices.

Our customers also indicated that they (generally) had a low interest in pursuing electrification of process and home heating, installing solar PVs, buying electric cars or installing batteries. The exception was that industrial customers were considering electrifying their vehicle fleet. This supports our view that demand growth due to electrification in our region will likely lag national trends.

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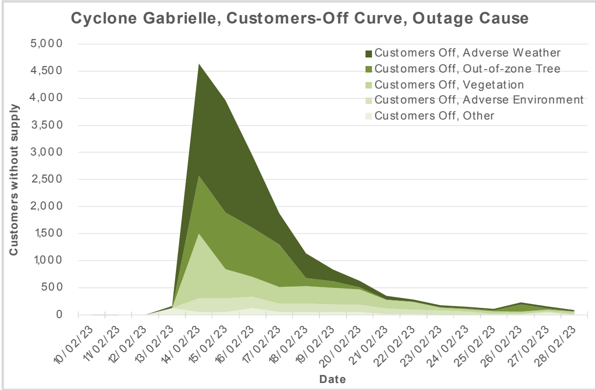
1 Winter line rating and winter peak demand. Winter peak demand is after netting off 4.4MW of generation. Gross peak demand was 54.9MW.

2 Source: World Energy Council.

1.4.9 The impact of Cyclone Gabrielle

Cyclone Gabrielle hit the Hawkes Bay Region on 12 February 2023. Considered the costliest tropical cyclone on record in the Southern Hemisphere, the total damages from cyclone Gabrielle are estimated to be at least NZ$13.5 billion.

Figure 6: Distribution customers-off during cyclone Gabrielle



Most of our network performed very well. However, the infrastructure was severely damaged in some areas, and our network was no exception. Distribution network outages impacted 4,500 ICPs at the peak of the event. Due to the damage to roading and our network, it took us more than two weeks to restore supply to a few isolated customers following the cyclone events (refer to Figure 6).

The most significant causes of outages were out-of-zone trees and very-high windspeeds damaging the network (the adverse weather outages in Figure 6).

1.4.10 Our recent network reliability challenges

Firstlight is regulated under the DPP regime, including a “cap” on unplanned SAIDI and SAIFI.[3] Under the regulatory regime, major events are normalised to reveal an underlying trend in reliability. This process is referred to as “normalisation”. From RY2021, the cap was reduced for unplanned SAIDI and increased for unplanned SAIFI.

Over the past four years, we have exceeded our unplanned SAIDI target, in RY2023 due to the impact of extreme weather. The East Coast and Wairoa regions are increasingly being impacted by extreme weather. In RY2023, there were 44 extreme weather days (MetService red and orange events), up 214% from RY2020. The increasing incidents of extreme weather events are the primary driver of unreliability on the network. The impact of extreme weather events has not been as material on SAIFI (refer to Figure 8).

Figure 7: Normalised SAIDI vs. Target

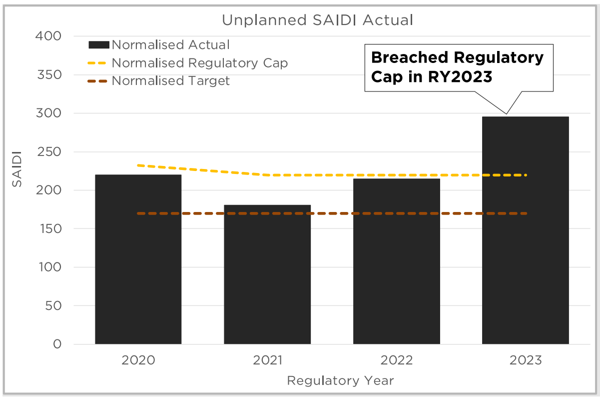
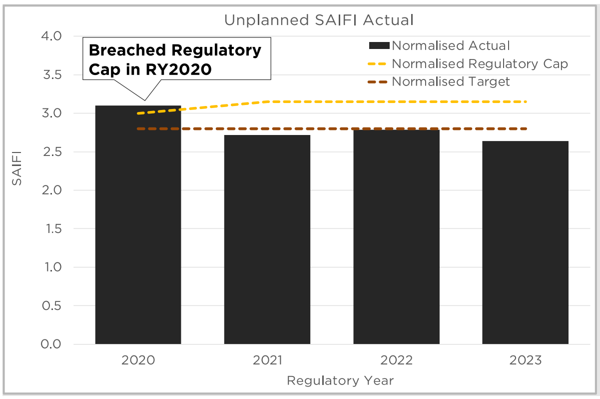


Figure 8: Normalised SAIFI vs. Target



Adverse weather and adverse environment SAIDI has increased materially since RY2020. In the RY2022 and RY2023 (periods when the incident of extreme weather was high), 85% and 95% of the SAIDI occurred during an extreme weather event (refer to Figure 9). The worst-performing feeders accounted for 85% of the adverse weather SAIDI and 93% of the adverse environment SAIDI.

[3] The unplanned outage cap only came into effect from RY2021. Before RY2021, the cap included both planned and unplanned outages. We have recalculated an unplanned cap for periods before RY2021 to provide a useful time series.

Increasing the resilience of these feeders is a key focus of our revised resilience strategy outlined in this AMP.

Figure 9: Adverse weather and adverse environment SAIDI on Extreme Weather Days

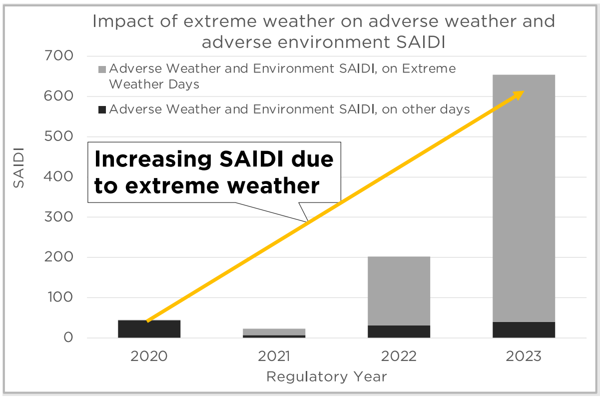
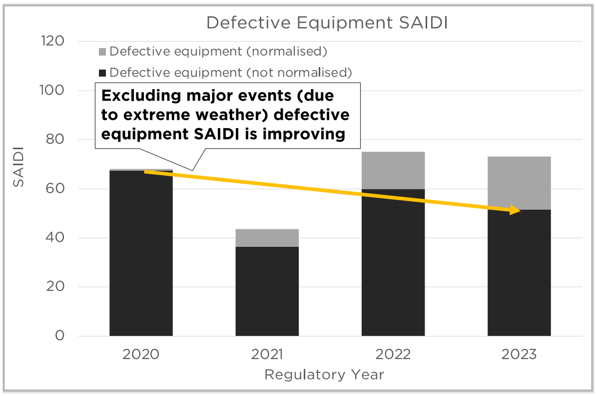


Figure 10: Defective equipment SAIDI



Pleasingly, and despite the extreme weather, we generally see an improvement in defective equipment SAIDI (refer to Figure 10).

1.5 Asset Management Strategy

1.5.1 Supporting Firstgas Group's strategy and stakeholder interests

Consistent with the Firstgas Group vision and mission mentioned earlier, Firstlight is committed to providing services that meet customers' needs and supporting the growth and prosperity of the Gisborne and Wairoa regions.

We have developed an asset management policy (in Section 7.2) that sets the principles to guide the direction and approach to managing the electricity network consistent with Firstgas Group's vision and mission.

Asset Management Strategy

The asset management strategy sets the direction for managing the electricity network assets. It has been developed to address factors that influence the business, improve performance, address the needs of all stakeholders, and comply with the asset management policy.

We have made two material changes to the asset management strategy in this AMP. The first change was to enhance the resilience initiative. This is now more wide-ranging in response to the impacts of climate change on extreme weather events. The second change is to bring in the energy trilemma as a key strategy in response to upward pressure on prices.

The asset management strategy consists of eight initiatives, and these are described in more detail in Section 7.

Initiative
1. Improve network resilience
2. Enhance vegetation management activities
3. Enhance asset fleet plans
4. Increase the level of security and automation on the network
5. Ensure the network can support the energy transformation and decarbonisation of the region

Initiative
6. Develop solutions to cater for demand growth from new industrial load and electrification
7. Improve asset management practices and asset information
8. Balance the Energy Trilemma consistent with stakeholder expectations

1.5.2 Balancing the energy trilemma

The Energy Trilemma is a well-recognised model for assessing the optimisation and balance across security of supply, affordability to customers, and sustainability. For Firstlight, this balance involves:

- Making suitable investments in the network to ensure it is secure and resilient;
- Making timely investments in the network to ensure it can support New Zealand's decarbonisation efforts;
- Ensuring our services are affordable to our customers.

The importance of the trilemma balance has increased for Firstlight due to the growing need for higher opex and capex to respond to our aging asset fleet, improve resilience, and support the electrification of transport and process heat.

Figure 11 shows our initial assessment of how the energy trilemma balance will evolve. This assessment indicates the direction of travel over the 10-year horizon of this AMP. The direction is shaped by:

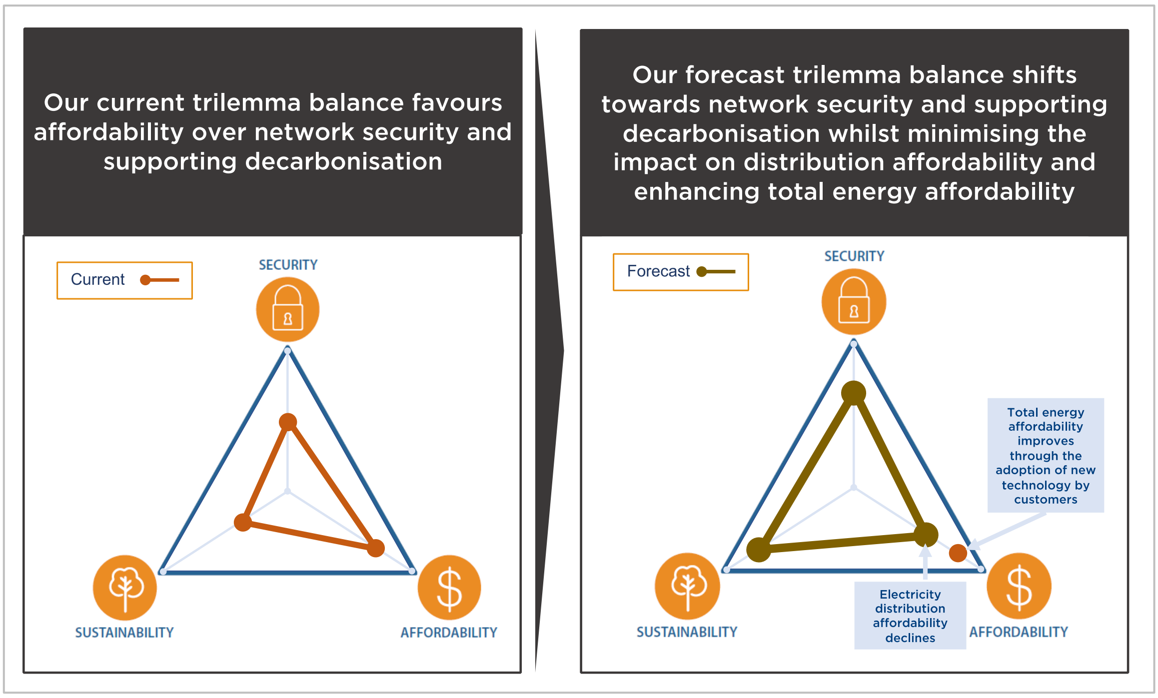
- Improving reliability outcomes through an increase in investment in network resilience, security, automation, and vegetation management;
- Investments in network augmentations (or alternatives) to ready the network to support the region's decarbonisation efforts;
- A decline in distribution affordability due to the abovementioned investments.

The key trade-off is that customers will see higher future distribution costs that will enable a network to support them as they transition parts of their energy usage from fossil fuels to electricity. Customers will also be connected to a more secure and resilient network that should respond and recover more quickly from climate-induced impacts.

We consider that it is appropriate to prioritise security and sustainability for three reasons:

- To maintain overall energy security for customers;
- To enable customers to reduce their total energy costs;
- To maintain consistency with the customer's priorities.

Figure 11: How the Energy Trilemma Balance will Evolve



1.5.3 Service levels

We have established service levels consistent with the asset management strategy, regulatory environment, and expected improvement. In general terms, service-level targets cover the following:

- Safety—where our target is for no harm to people and no serious damage to property;
- Customer service—where 80% of customers rate reliability, affordability and communication good to excellent;
- Network reliability—that meets our internal target (in a normal year) and is below our regulatory cap (in all years);
- Asset utilisation and efficiency—where we are targeting improvement in the underlying performance of the assets (i.e. a reduction in underlying asset failure rates);
- Delivery—where we target to deliver 95% of our planned capital works program and condition information to support asset health assessments.
- Financial sustainability—where we achieve our regulated return on investment.

The full details of service levels are included in Section [8].

1.6 Implementation of the Asset Management Policy and Strategy

The implementation of the asset management policy and strategy is delivered through our:

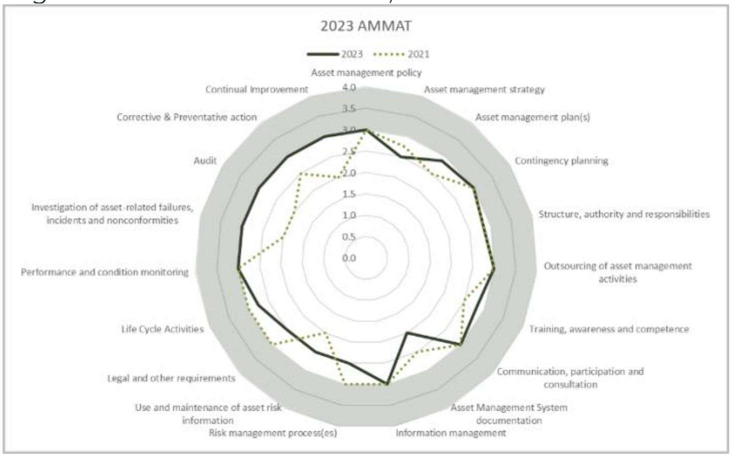
- Asset management improvement roadmap;
- Lifecycle (network development) plans;
- Lifecycle (network maintenance and renewal) plans;

These plans are supported by the risk management and delivery processes.

1.6.1 Asset management improvement roadmap

In the 2021 AMP, the roadmap for improving asset management practices was outlined. The objective of the roadmap was to transition to a fully proficient asset manager by the end of FY2023, equating to a score of 3.0 on the AMMAT scale. The year has been challenging and busy due to the weather events and the transition to Firstgas Group. Over the course of RY2023, we have improved our AMMAT score but have not achieved a score of 3.0. Given the competing priorities we face, we now anticipate that this will be achieved by RY2025.

Figure 12: Movement in AMMAT, RY2021 to RY2023



Our AMMAT score improved from 2.7 to 2.8.[4] The key areas of improvement were continuous improvement, corrective and preventative action, investigation into asset-related failure, and use and maintenance of asset risk information. Some areas have seen a slight reduction in scoring, and these areas will be addressed over the course of RY2024 (refer to Section 9.2).

1.6.2 Lifecycle (network development) plans

Revisions to demand forecasts

Forecast maximum demand has increased in this AMP compared to our 2021 AMP. In 2033, we are forecasting the Gisborne region's maximum demand at 66 MW, which is up 8% on the 2021 AMP and the Wairoa region's maximum demand at 13 MW, which is up 20% on the 2021 AMP (refer to *Figure 13* and *Figure 14*). The forecast demand includes a 4 MW prudent planning margin for Gisborne and 1 MW for Wairoa.[5] The higher demand forecast in RY2033 was driven by the increased demand growth experienced between RY2020 and RY2023, which was 9% for Gisborne and 20% for Wairoa. The demand growth has been tempered by a lower contribution from EV charging in RY2033. This is due to the current EV registrations in the region being lower than we forecast in the 2021 AMP. Our EV uptake rate is forecast to be lower than the national growth rate due to the socio-economic differences in our region.

Our demand forecasts do not explicitly include a reduction in hot water demand response and electrification of gas load; however, we suspect that some of the higher growth in recent years reflects these factors. Hence, a reduction in hot water control and electrification is likely inherent in the demand forecasts. We will seek to assess this when preparing the demand forecasts for the 2024 AMP.

[4] The assessment scale is from 1.0 to 4.0. An AMMAT score of 3.0 reflects the level of a fully competent asset management and a score of 4.0 reflects a level that surpasses that required in ISO 55000.
[5] These planning margins are the same as included in the 2021 forecasts.

Figure 13: Gisborne region demand forecasts

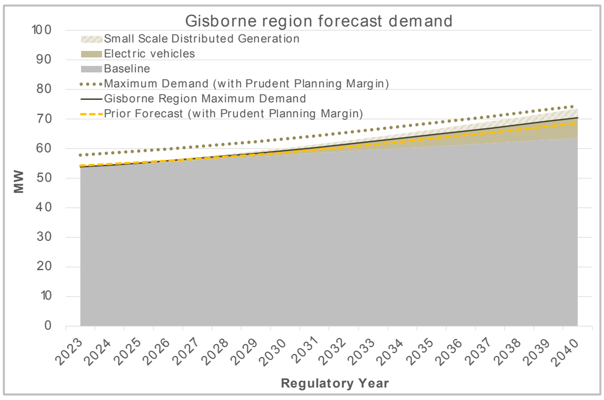
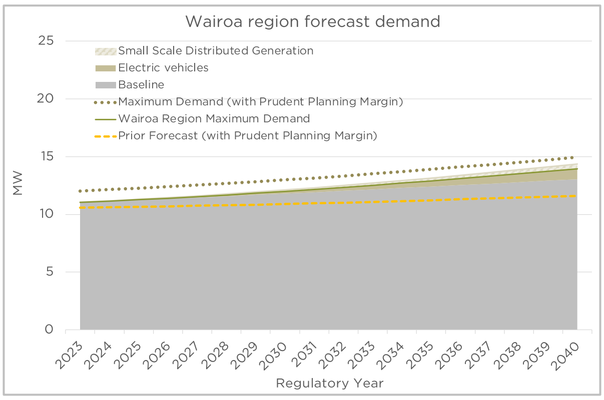


Figure 14: Wairoa region demand forecasts



Significant development project to increase capacity

In the 2021 AMP, we included a new project to increase the capacity into the Gisborne region. The project will increase capacity from 55.5 MW to 68 MW and consists of:

1. A capacity bank upgrade at the Gisborne substation (by RY2023);
2. A thermal upgrade of GIS-TUI 110kV lines to operate at 75°C (by RY2028);
3. A further capacity bank upgrade (by RY2034).

Design work on the capacitor upgrades is progressing, and this work is now forecast to be completed in RY2026. The thermal upgrade work is progressing and is now forecast to be completed by around RY2030. The delays have not caused any concerns as the design work has revealed a further option to operate Tuai GXP at a higher bus voltage to improve capacity. This voltage option can be implemented at short notice. The upgrades are forecast to cost $10.6m over the next ten years (down around $1m on our 2022 AMP).

In this AMP, there is one significant new development projects.

- Wairoa Substation: the transformer capacity is insufficient to meet the long-term demand forecast. Reconfiguration of the site will be required. The work is planned over several stages between RY2025 and RY2033 at a cost of $3.2m;

The other significant projects, which are broadly consistent with the 2021 AMP, include:

- New Massey zone substation: This project involves re-establishing the Massey substation to support the Port, Makaraka, and Kaiti substations. The work is currently planned for RY2027 to RY2028 at a cost of $1.9m, an increase of $300k over the 2022 AMP;
- New Whangara zone substation: This project involves developing a new 2.5 MVA substation at Whangara. It is proposed to utilise the 50kV sub-transmission line running alongside the 11kV line and install a 2.5 MVA zone substation at Whangara. This location is the tie point between the Rototahi, Dalton, and Waimata feeders and addresses forecast voltage constraints on these feeders. Additional load from the Kaiti substation can be offloaded onto this new substation, easing the contingency constraint projected for the substation. This project has been delayed by two years and is now forecast for completion in RY2032. The project costs have increased by $500k to $2.1m;
- New Mahia substation: This project involves a 33kV line extension and 2.5 MVA substation to support growth and reliability for Mahia. This project has now commenced; However, the start was delayed by two years due to delays in securing property rights. The project budget is $2.6m, and around $1.0m is required to complete the project from RY2024 to RY2026.

- Puha Zone Substation 11kV backup. This project involves constructing an 11kV line extension to provide backup to the Puha substation. The project budget is $520k and is due for completion in RY2026.

Resilience strategy and associated network development work

The enhancement of our resilience strategy is ongoing. However, to date, the new initiative comprises the eight actions shown in *Table 1* below. The resilience strategy combines some existing workstreams and commences new work to better understand wind, flooding and geotechnical vulnerabilities that have become more acute due to climate change.

Table 1: Resilience strategy

Initiative	Description
1. Improve network resilience	Improve the resilience of the network to adverse weather events through: • Assessing wind, flooding and geotechnical hazards and implementing mitigation plans where appropriate (consistent with climate change); • Assess the worst-performing feeders to determine if there are improvement opportunities available; • Assessing the risk posed by pre-2000 overhead lines and implementing mitigation plans where appropriate; • Enhancing our contingency plans, mutual aid plans, and spares holding; • Enhancing our SCADA and OMS; • Enhancing vegetation management activities concerning key feeders and the out-of-zone trees (see asset management strategy #2); • Increasing distribution network automation and security enhancements, particularly the opportunities to enhance generation use (see asset management strategy #4).

The full scope of work has not yet been defined, and we expect to include additional projects in the 2024 AMP. However, in this AMP, three new development projects have been included:

- The installation of three new 750 kVAe generators at Raupunga, Frastertown, and Ruakituri to enhance supply security in FY2025 to FY2029, at a cost of $3.2m;
- The installation of a second transformer at Tolaga Bay to improve the firm 11kV capacity available from Tolaga Bay to support adjacent substation;
- Replacement of the SCADA masterstation and development of switch-order management and outage management system in RY2026 to RY2027 at the cost of $2.6m.

Cyber security forms an important part of our overall business resilience strategy. This is covered seperately in Section 9.

Automation, protection, and distribution backup work

Further supporting our resilience strategy, we have increased the scope of our automation program to improve feeder security and reliability through additional reclosers and switch automation. These projects total $1.2m over the planning period, an increase of $460k from our 2022 AMP. Refer to Sections 10.6.2 and 10.7 for further details.

Enabling decarbonisation by supporting electrification and distributed generation

Reducing emissions through electrification and increasing renewable generation are critical to achieving net-zero 2050. In particular, the electrification of transport and heat (both process and general) and the use of distributed energy resources (**DERs**) are central to New Zealand's decarbonisation.

There is general recognition of electricity distribution businesses' importance in the energy supply chain. Distributors form the critical link between consumers and energy markets and can enable greater participation by consumers in the decarbonisation efforts.

We undertook further network modelling of electrification during RY2023, indicating that the subtransmission and distribution network will generally be able to cope with the expected EV and small-scale distributed generation uptake over the next ten years. There may be some localised capacity upgrades, and we have increased our budget for distribution transformer and LV cable upgrades by $2.0m to cater for this growth.

Other than the prudent planning margin included in our demand forecasts, we have not yet assessed the potential impact of electrification of process heat. We have surveyed our major customers' intentions concerning electrification, which does not indicate any near-term issues; however, we recognise that things can change rapidly. Further studies and modelling work are planned over the coming year and will be included in the 2025 AMP. Any material increase in demand could require our Gisborne capacity enhancement project to be advanced. Significant electrification of process heat will likely require zone substation and distribution upgrades—none of which has been included in this AMP.

In the 2021 AMP, we included an initial view of the "future state" model for electricity distribution businesses. Work has progressed since then, and there has been an increasing focus on how demand and DER response will work (these are now commonly referred to as flexibility). Our current demand forecasts are based on Firstlight's access to flexibility (i.e. hot water demand response and off-peak EV charging). It is not certain that we will continue to have priority access to flexibility, as this may be required to respond to intermittent generation for system security purposes. We have yet to fully model the implication of not having firm access to flexibility. This will be included in the 2024 or 2025 AMP.

Section 10.9 describes our current plan to support electrification and distributed generation in our region.

1.6.3 Lifecycle (network maintenance and renewal) plans

Asset fleet plans

In Section 11, we describe comprehensive fleet plans for our material asset classes, which includes structures (wooden and concrete), structures (steel), conductor, power transformers, substation switchgear, distribution transformers, and distribution switchgear. These assets represent 92% of the total value of the network (in RAB terms).

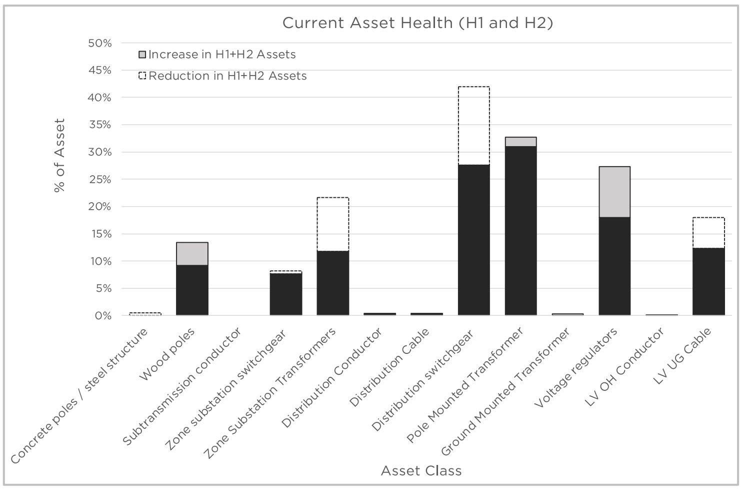
Our fleet plans are transitioning from an age-based renewal forecasting to an asset health-based approach that utilises asset condition data and the DNO common network asset indices methodology. The DNO common network asset indices methodology is a framework of definitions, principles and calculation methodologies for assessing and forecasting asset health and asset risk. This methodology has been adopted by all distribution network operators across Great Britain and is commonly used in New Zealand.

Current asset health and renewal forecasts

Figure 15 shows the percentage of assets that are falling due for renewal (i.e. H1 is where replacement is recommended, and H2 is where end-of-life drivers for replacement are present).

These forecasts are a mix of age and condition-based (as not all the asset fleets have been inspected under our condition assessment regime). There has been some movement in the health of some assets due to improving condition data as inspections are completed.

Figure 15: Current Health of Material Asset Clases



The increase in the low-health wood poles and voltage regulators is as expected and is consistent with our expectations as we inspect the older areas of the network. These asset fleets have appropriate renewal plans in place. In the case of pole-mounted transformers, this fleet health forecasting is age-based, leading to an over-forecasting of low-health assets. We will transition this fleet to a DNO-based methodology that more accurately assesses health.

Distribution switchgear includes both condition-based (for ground-mounted) and age-based (for pole-mounted). The age-based health assessment for pole-mounted switchgear has led to over-forecasting low-health assets. Based on the currently low failure rate for these assets, we expect an increase in the age for the onset of unreliability for this asset class, reducing the extent of low-health assets.

Figure 16: Forecast Asset Health and Renewals for Material Asset Classes

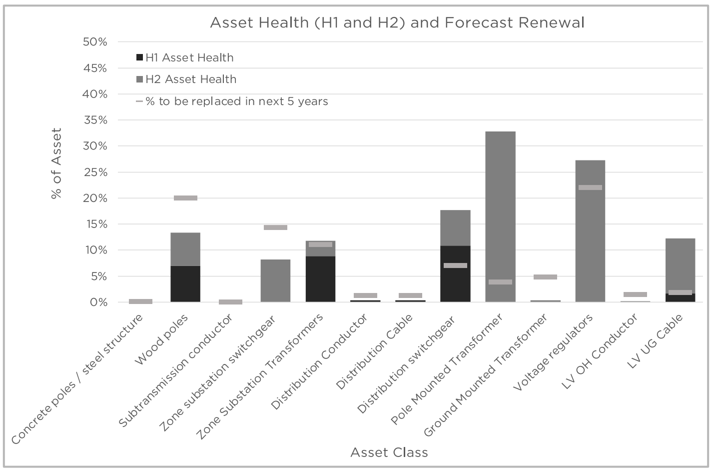


Figure 16 shows the forecast asset health (in 5 years) and asset renewals over the next five years.

As mentioned in the section below, we have accelerated our wood pole replacement; hence, we are forecasting renewals above the level of low-health assets.

Forecast renewals for pole-mounted transformers and (pole-mounted) distribution switchgear are appropriate as these fleets are currently over-forecasting low-health assets.

<u>Accelerated wood pole replacement program.</u>

In the 2022 AMP, we accelerated the replacement of our wood pole fleet in response to the results of our inspection program (which was to a new, higher standard). The increase in low-health poles was not unexpected (and the 2021 AMP had forecast renewals above the level of H1 and H2 poles in contemplation of this). The plan involved replacing an additional 530 poles during FY2023 and FY2024 at an additional cost of $4.4m.

Given the results of the most recent health assessments and the windspeed damage durning cyclone Gabrielle (which was likely above design limits) we have further extended our wood pole replacement program. We plan to replace 20% of the fleet over the next five years, with over 8% of the fleet being replaced in the next two years. The additional cost of the program over that period is $8.6m.

Improving vegetation management activities

Reducing vegetation-related outages is a key strategy for the business, and we are targeting a 5% reduction in vegetation outages each year (from RY2021 to RY2026). We achieved these targets in RY2021 and RY2022 but missed them in RY2023 due to the significant increase in extreme weather. During the major events of RY2023, we saw significant damage from out-of-zone trees, and as a result, we have increased the focus on this issue in our vegetation management strategy.

In terms of our strategy:

- Our work on managing vegetation has shown positive results. On these feeders, vegetation SAIDI reduced from 18 SAIDI in RY2020 to 8 SAIDI in RY2022;
- The intensive subtransmission vegetation management has also shown positive results. There was no vegetation related SAIDI on the subtransmission network in RY2021 and RY2022.

Given the vegetation damage sustained in RY2023, we have increased our forecast spend on vegetation by $2.1m (18%) over the next ten years[6].

Our vegetation management strategy is included in Section 11.23.

1.6.4 Risk management

Risk oversight

At Firstlight, risk management activities occur at an operational level, management level, and at a governance level:

- The Board defines Firstlight Network's risk appetite and oversees the management of strategic and significant operational risks;
- Management identifies and manages strategic risks and oversees operational risks and associated risk management activities;
- Operational personnel identify and manage risks as part of normal asset management activities.

Risks are considered at two levels:

- Strategic risks—these are risks that could have a significant impact on Firstlight's business and long-term objectives;
- Operational risks—these are risks inherent in the routine operation of the business.

Strategic risks

There are six strategic risks associated with Firstlight Network. These are summarised in *Table 2* below:

Table 2: Strategic network risks

Risk title	Current controls and planned treatments
Climate change increasing the damage to the network and outages to customers	Controls have been implemented to manage climate risk. However, further treatments are planned as part of our strategy to improve resilience.
Death or injury resulting from activities under Firstlight's control	Significant controls are in place through safety systems and management of safety culture.[7]

6 Before the change in time-writing process which allocated some of the prior system operations and network support costs to network opex categories. This is explained in Section 1.7.

7 This includes vehicle accident risk, which was previously identified as a separate risk in the 2021 AMP.

Risk title	Current controls and planned treatments
Significant power outages to customers	Asset management activities and contingency plans are the key controls.
Significant reduction in electricity demand	Network revenue is protected through the revenue control regime of the default price path
Failure to support electrification and renewal generation	Work has commenced to enable the business to support the electrification of transport and heat, the increase in distributed renewable generation, and possible change in the availability of flexibility (demand response).

Operational risks

The asset fleet plans in this AMP contain details of the general and specific operational risks associated with each asset class. The fleet plans also include program details to manage or mitigate these risks. Overall, all high-risk issues identified have programs to reduce the risk. Refer to the asset fleet plans in Section 11 for details.

Refer to Section 12 for additional details on risk management activities and key strategic and operational risks.

1.6.5 Deliverability

In the 2021 AMP, we established a target of completing 95% of planned work in any year. We achieved this target in RY2022 and RY2023 except for system growth in RY2022 (which was due to land consenting delays).

In response to the consenting and land acquisition delays, we plan to leverage the internal capabilities of Firstgas Group to enhance delivery in this area.

We have increased our expenditure forecasts in this AMP, and this will increase the field resources required to complete the planned work. In response, we are planning to expand our utilisation of external contractors. This needs us to have suitably sized work packs to make it efficient for out-of-region contractors to relocate teams. This worked successfully in RY2022 on our accelerated pole replacement program (the program was disrupted in RY2023 due to the extreme weather that year).

1.7 Changes in our forecast expenditure

1.7.1 Changes in time-writing and capitalisation process

The transition to Firstgas Group systems introduced new time-writing processes at Firstlight. This transition has resulted in some changes to opex and capex:

- The level of capitalisation of business support (**BS**) and system operations and network support (**SONS**) costs has been reduced. This has increased BS and SONS costs;
- The time-writing of some SONS costs to network opex categories. This has offset the increases mentioned above. Within the SONS team, some staff undertake asset inspections, vegetation administration and other work that directly relates to network opex, and these costs have now been forecast as network opex.[8]

Our commentary on the changes to network opex forecasts explains this on a comparable basis.

Our commentary below references constant dollars.

[8] Our approach was to apply a contractor lense to these resources. That is, if the staff would ordinarily be part of a field services contractor performing the work then their costs were time-written to network opex. Our assessment was taken over a relatively short period, and our allocations (for forecasting purposes) may change over the coming years.

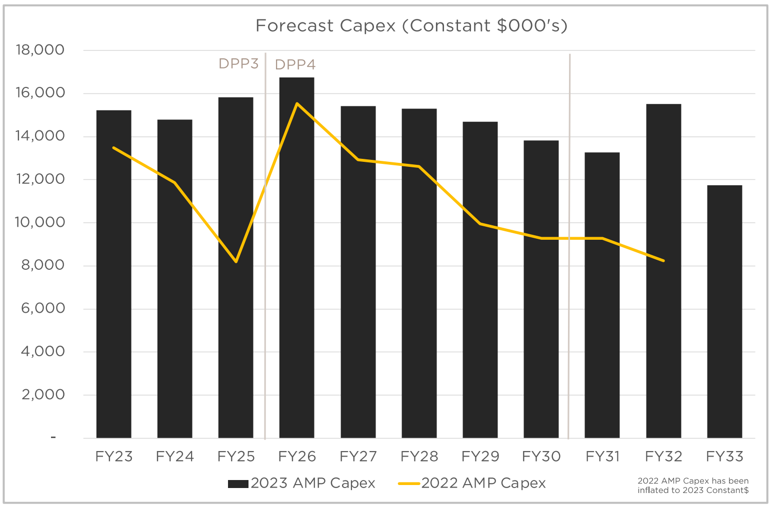
1.7.2 Changes in forecast capex expenditure

The network capex forecast for the next five years averages $15.6m (refer to Figure 17). This is an annual increase of $3.6m over the 2022 AMP.

The increase in expenditure has principally been driven by an increase in renewal expenditure and quality of supply expenditure. We have also seen a material rise in the cost of doing work, with some project costs increasing by 20%.

The increase in renewal expenditure is due to additional wood pole renewals, addressing access and geohazards on the 110kV tower lines, and the commencement of generator refurbishments.

Figure 17: Forecast Capex



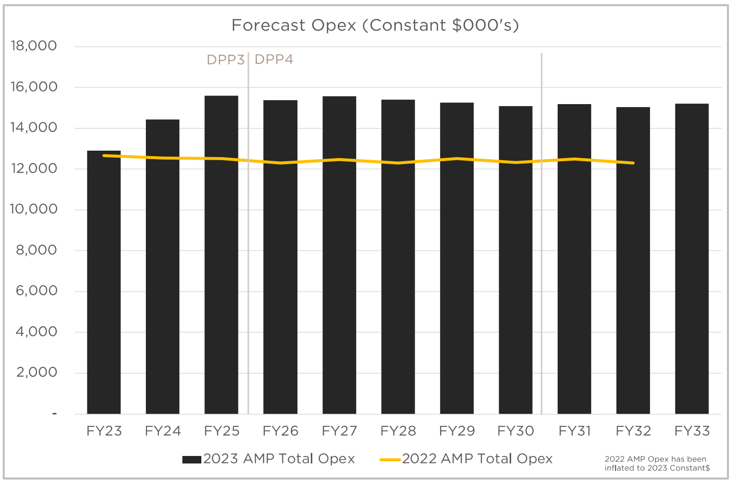
The increase in quality of supply expenditure relates to the new backup generators and the upgrading of the SCADA masterstation and outage management system.

The increase in capex is significantly more than our current regulatory allowance. We are forecasting overspending our capex allowance by 59% in RY2024 and 67% in RY2025.

1.7.3 Opex forecasts

Total Opex averages $15.2m over the next five years. This is a $2.8m p.a. (18%) increase over the 2022 AMP.The increase in expenditure is due to a material increase in emergency response, vegetation management, and inspection and maintenance costs. The change in time-writing mentioned above has also increased overall opex (with a corresponding reduction in capex).

Figure 18: Forecast Opex



Service interruption and emergency opex have increased by $1.0m million[9] p.a. These costs reflect our current costs (based on the likelihood of ongoing extreme weather events). It also now includes operating costs (i.e. diesel) associated with the gensets. This cost increase is before the implementation of our full resilience strategy. The resilience strategy's goal is to reduce the impact of extreme weather. Hence, when implemented, service interruption and emergency opex will be reduced[10]. When we have included the full capital costs of the resilience program in our forecasts, we will include the benefit (i.e. reduction) in emergency response opex.

9 Before time-writing allocation.

10 The cost of new generators has been included; however this doesn't reduce the impact (damage) to the network; rather these are a means of maintaining supply.

As mentioned in Section 1.6.3, we have increased our forecast for vegetation management work by $210k p.a.[11]

Routine and corrective maintenance and inspection costs increased by $400k p.a. We are increasing network inspection activity as our asset fleets age. We have also included maintenance costs associated with the diesel generator fleet.

1.8 Stakeholder Feedback

Firstlight is on a continual improvement path to better manage asset-based activities. Feedback, comments or suggestions concerning this AMP are to be directed to the Manager, Project Delivery and Asset Management for Firstgas Group. Contact can be made through the Firstlight public email address: info@firstlightnetwork.co.nz.

All other information can be found on the Firstlight Public website.
https://www.firstlightnetwork.co.nz/

[11] Before time-writing allocation.

2. Introduction and Background

This section provides an overview of Firstlight Network, including ownership, governance and responsibilities for asset management. This section explains Firstlight approach to asset management lifecycle management and the key corporate plans that influence this AMP.

2.1 Introduction

2.1.1 Purpose of this Firstlight Network Asset Management Plan (AMP)

This AMP has been prepared consistent with the asset management policy and strategy included in previous plans (other than enhancing the resilience strategy). Over the next 12 months, the policy and strategies will be reviewed to ensure alignment with the Firstgas Group's strategic objectives.

The purpose of this AMP is to communicate with all stakeholders by:

- Presenting the operating context and performance drivers for the network;
- Presenting the asset management policy and strategy;
- Describing how the network is performing and how any performance challenges are being addressed;
- Outlining the roadmap for improvements to asset management practices and information;
- Presenting quality and other performance targets;
- Outlining plans of how the development of the network will meet the asset management strategy, and the needs of all customers;
- Describing the lifecycle asset management (maintenance and renewal) plans that will ensure that the network can continue to meet its quality and other performance targets;
- Providing details of forecast expenditure on the network and related assets.

2.1.2 How this AMP is set out

This AMP continues our focus on highlighting the key asset management issues, direction, and decisions. Evidence supporting the direction taken and decisions made by Firstlight is also presented. Stakeholders will benefit from a greater focus on key matters.

The AMP is set out in three parts:

- Part 1: Factors that are influencing policy and strategy;
- Part 2: The asset management policy and strategy;
- Part 3: Implementing the asset management policy and strategy.

Setting out the AMP in this manner clearly informs stakeholders of the material issues considered when developing the strategy for managing the network and clearly explains the development and lifecycle plans that will be implemented to achieve this strategy.

2.1.3 Period covered by this plan

This plan covers a ten-year period from 1 April 2023 to 31 March 2033 (regulatory years 2024 to 2033 – the planning period). As with any long-term plan, the details tend to be more accurate in the earlier years as the near-term state of the assets is easier to predict and plan required actions and expenditure.

Following the acquisition by Firstgas Group, the financial year of the company was changed to 30 September. As this AMP is guided by the Information Disclosure determination and supports various regulatory processes, the annual periods referenced in this document continue to be from 01 April to 31 March, which are now referred to as regulatory years ("RY").

2.1.4 Approval of this plan

This Asset Management Plan was approved by the Firstlight Network Limited Board on 27 September 2023

2.1.5 Technical terms

This document contains a number of industry-specific terms and acronyms and we have explained these are explained in Appendix 1.

2.2 About Firstlight Network

Firstlight owns the electricity distribution assets that supply Gisborne, Wairoa and the East Coast. In addition to the distribution network, Firstlight owns the region's high voltage electricity transmission network that now forms part of the sub-transmission system and connects the region to the national grid and owns five 1 MVAe Diesel generators located at Puha, Ruatoria, Te Aroroa, Tolaga and Mahia.

Figure 19: Firstlight Network's region

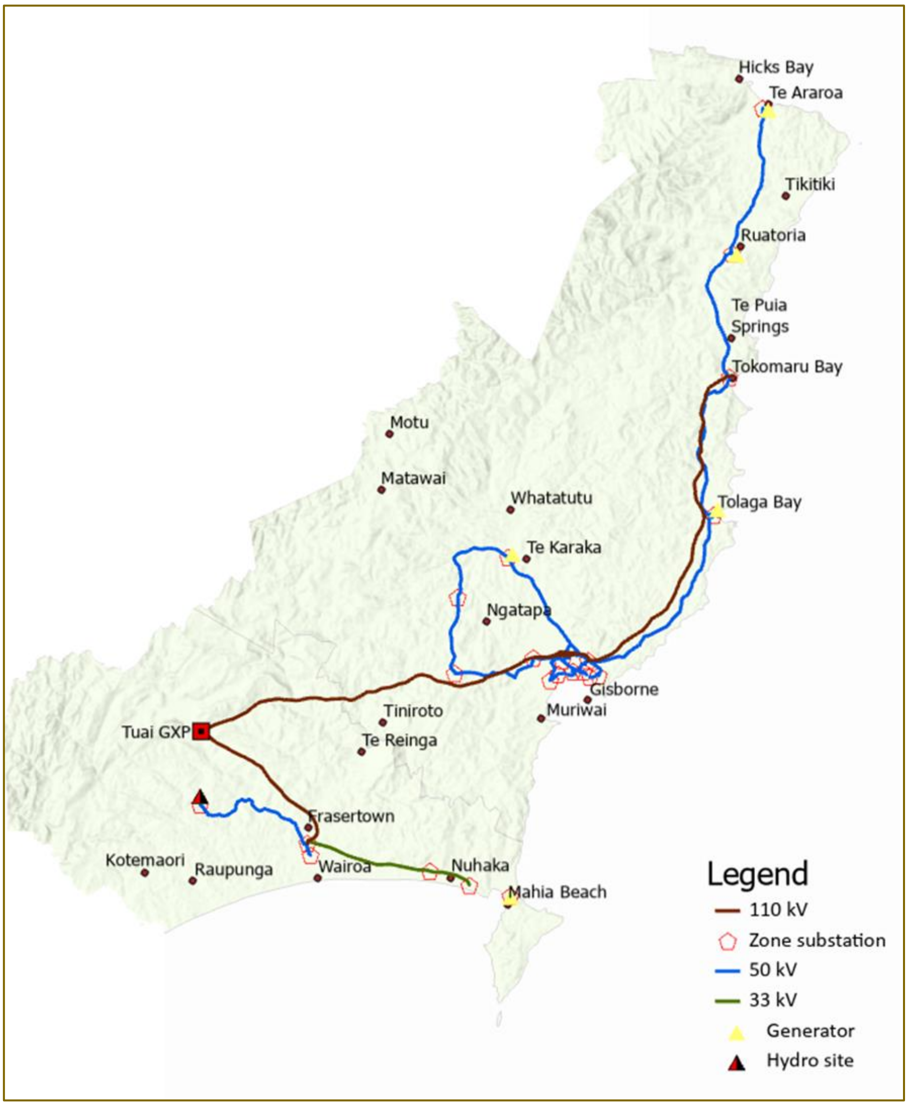


Table 3 summarises the key statistics for the network as of 31 March 2023. Firstlight is a predominately overhead network with substations located throughout the region to supply urban centres and rural communities. Diesel generators are located to supply security of supply for rural communities.

Table 3: Key Network Statistics

Asset type	Quantity
Diesel generators	5
Zone substations	21
110kV subtransmission lines	307 km
50kV and 33kV subtransmission lines	336 km
11kV distribution lines	2,380 km
11kV distribution cables	141 km
LV lines	504 km
LV Cables	275 km
Percentage of overhead lines	89%
Percentage of lines and cable in rural and remote rural areas	85%
Percentage of lines and cables in urban areas	15%
Poles (concrete and steel)	18,122
Poles (wood)	17,016
Consumer service connection points	26,300
Regulated asset base (RAB)	$209.4m

2.3 Ownership and governance

In 2023 Firstgas Group acquired Eastland Network Limited from Eastland Group, with the transaction completed on the 31st of March 2023. Eastland Network comprised the operations, engineering, and planning team, but excluded the corporate functions and systems that were previously provided by Eastland Group to Eastland Network.

Eastland Network was renamed Firstlight Network and is part of the Firstgas Group, which is owned by Igneo Infrastructure Partners.

Igneo Infrastructure Partners, part of the First Sentier Investors Group, has invested in infrastructure for over 30 years and is one of the leading infrastructure asset managers worldwide.

The Firstgas Group Board[12] governs the management and operations of Firstlight.

2.4 Organisational structure

Firstlight transitioned into the Firstgas Group on the 1st of April 2023. This included:

- Adoption of Firstgas Group's corporate and asset management systems;
- Provision of corporate support from Firstgas Group;
- Integrating the operations, engineering and planning roles within the Firstgas Group operations structure and the contracting of asset management services via GSNZ;

12 The Firstgas Group Board and the Firstlight Network Limited Board are the same.

Firstgas Group operates a shared services model across its businesses. This provides capacity and capability within the subsidiary company that would not otherwise be available to a stand-alone business. The following functions are provided by Firstgas Group to Firstlight:

- Treasury and financial services;
- Regulatory services;
- Business development;
- People and culture services
- Information technology services.

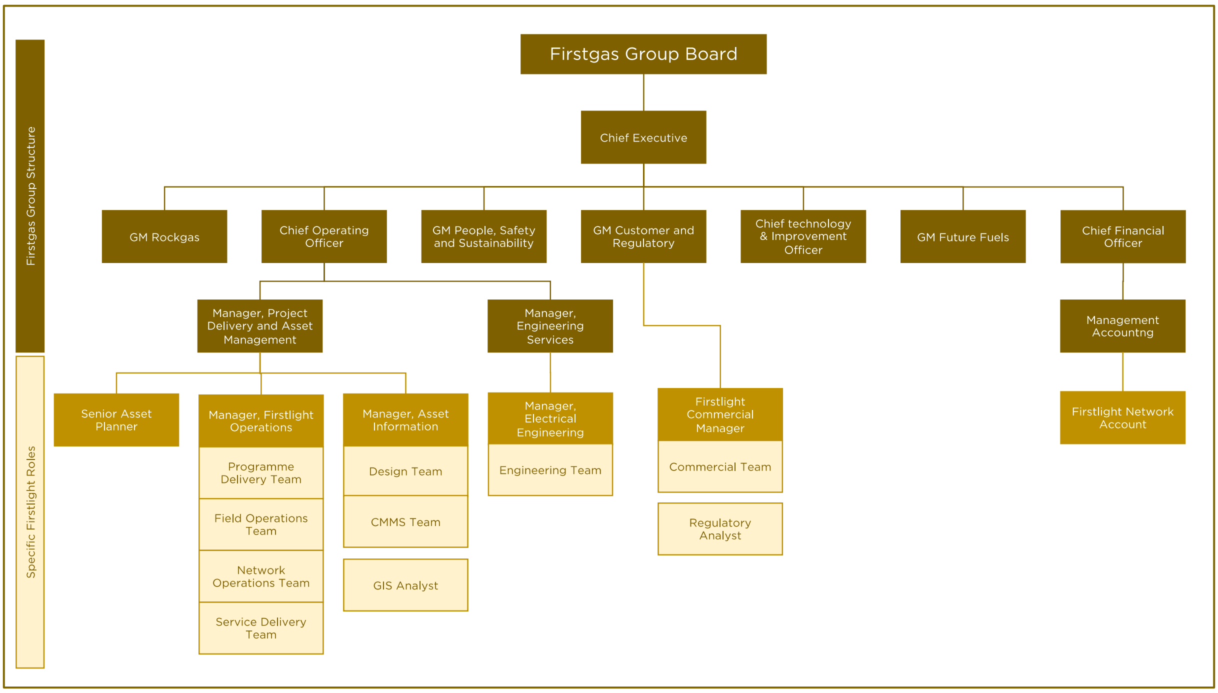
Firstgas Group also provides the overarching policies and procedures to all its businesses; however, specific asset management plans, policies, and procedures are the responsibility of each individual subsidiary.

Firstgas Group provides integrated asset management, operations, maintenance, and related services to group companies through its associated GSNZ company. This provides technical capacity and capability to the individual group companies that would not otherwise be available.

The Firstlight operations team, engineering team, senior asset planner, asset information team, commercial manager, and network account provide the core asset management capabilities. These roles are integrated within the Firstgas Group structure.

The Firstlight business is further supported by People, Safety and Sustainability, Information Technology and Finance.

Figure 20: Firstgas Group structure



External contractors are engaged to provide the additional resources and capabilities not held within the network's existing team, including;

- Vegetation maintenance;
- Asset maintenance, capital replacements, and renewals;
- Technical services;
- Asset inspections and testing;
- Additional fault response resources;

- Supply of goods and materials;
- Communications installation and maintenance
- Mechanical maintenance;
- Civil construction and transportation.

External contractors undertake almost all condition monitoring, installation, and maintenance work on network assets.

The Control Room monitors the network via the SCADA system. The Control Room is staffed during the day and then through an on-call roster after hours. The duty controllers have remote access to the SCADA system.

Call centre functions are outsourced to 'Your Call' who operate a 24/7 service that logs all fault calls for both the Gisborne and Wairoa regions. The call centre communicates with the Control Room for network fault management, dispatching fault staff, and managing access to the network.

2.5 Accountability for Asset Management

The Board and Executive Management team are responsible for governing and managing the business to achieve the strategic objectives set out in the business plan. Performance against objectives are reported regularly to the Board.

Responsibilities, objectives, and performance targets for Firstlight are described in the Business Plan, AMP, and the asset management improvement roadmap. These documents are approved by the Board, which monitor the performance against these plans.

Preparation of the AMP is a key accountability of the Senior Asset Planner, who reports to the Manager, Project Delivery and Asset Management. The Firstlight operations team, engineering team, asset information team, and commercial team provide significant input into preparing the AMP.

Understanding stakeholder needs and external drivers, assessing the network's performance, and determining the asset management strategy involves a wide number of people from across the Firstlight and Firstgas Group.

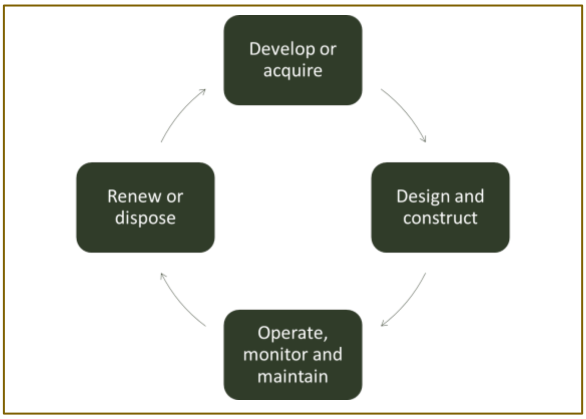
The engineering team is responsible for the collection and processing of the field inspection data, undertaking asset health assessments, and preparing renewal projects and expenditure forecasts. They also assess Firstlight's planning criteria that guides the development of the network and undertake demand forecasting and loadflow modelling to determine future network constraints and prepare development projects and expenditure forecasts.

The engineering and commercial teams are also responsible for communicating future network plans to stakeholders.

2.6 Overview of Firstlight's approach to Asset Lifecycle Management

There are different ways in which the life cycle of an asset can be described. The four key phases of an asset's lifecycle are presented in Figure 21 below and are representative of the focus for Firstlight. Asset management practitioners often include planning as the first phase, however Firstlight view planning as an overarching requirement for the entire lifecycle, and not a specific phase (noting that most planning occurs early in the lifecycle).

Figure 21: Phases of the asset lifecycle



The asset lifecycle and where each phase is addressed in the asset management process is described below.

2.6.1 Develop or Acquire

The *develop or acquire* phase covers the creation of an asset through development or acquisition and includes identifying the need, evaluating options, undertaking conceptual design work, and preparing the preliminary business case (if this is warranted by the scale of the project). The key purpose of this phase is to ensure the network is developed in an economically sustainable way, in response to the needs of the business, and in a timely manner.

Typically, new assets are developed or acquired in response to:

- Network growth and security (refer section 10.4);
- Network reliability enhancements (refer section 6.6 and 11);
- New customer connections and relocations of existing assets (refer section 10)
- Future network needs (refer section10)

2.6.2 Design and Construct

The *design and construction* phase covers detailed design, tendering, project business case and approval, project management, construction, and commissioning of new assets. The design and construction phase occurs in response to development needs (mentioned above) or renewal needs (mentioned below). The design phase has taken on increasing importance over the last decade as the phase where material risks (in relation to safety, reliability, longevity, and serviceability) can be engineered out through good design and selection of materials.

The key purpose of this phase is to create an asset that is economically efficient (over its lifecycle), has appropriate inherent risks, is delivered at the appropriate time, and meets the original business need.

How this phase is carried out for assets is detailed in Section 10.

2.6.3 Operate, monitor and maintain.

The *operate, monitor and maintain* phase covers the operation of the assets, ongoing inspection and testing, corrective and preventative maintenance, and any emergency response in relation to the assets. The key purpose of this phase is to ensure the safe and reliable performance of assets over their expected lives. This is detailed in Section 11.

2.6.4 Renew or Dispose

The *renew or dispose* phase covers the process of deciding when to renew and/or dispose of assets. Typically, the decision to renew an asset is made in response to:

- Declining asset health (or increasing age in some cases). Assets are forecast for replacement when their asset health indicator reaches (or is forecast to reach) H1 or H2. The actual replacement of the assets is subject to a detailed assessment of the asset condition and criticality;
- Deteriorating reliability performance;
- Safety and integrity concerns;
- Technical or operational obsolescence;
- The economics of ongoing maintenance (compared to replacing with a modern equivalent asset).

How this is undertaken for Firstlight's asset fleet is addressed in section 11.

In addition to the above-mentioned criteria, disposal of the asset happens when the asset is removed from service and cannot be redeployed or otherwise reused (which could be as a result of the criteria mentioned above).

2.7 Asset Management Systems Processes and Information

This is detailed in section 9 (asset management roadmap)

2.8 Key Plans and Interactions

The key plans and interactions are shown in Figure 22 and explained below:

Firstgas Group business plan: This document provides the overall guidance on the objectives for the subsidiary companies. It also provides the targets and direction Firstgas Group is looking to progress and is the overarching document driving the allocation of capital across Firstgas Group, including major acquisitions and divestments. The business plan is updated every 2 years, with the latest revision due for FY2024.

Firstlight Network business plan: This is the annual network business plan that defines the key initiatives supporting the achievement of performance targets. The AMP is a tactical plan and a repository for detailed asset information, these documents are closely coordinated during the business planning cycle.

Asset management policy: This policy aligns with the Firstgas Group's asset management policy and describes Firstlight's commitment to asset management. It provides the guidelines and principles that shape the asset management plan. The asset management policy is included in this AMP and is communicated to the business and stakeholders in various forums.

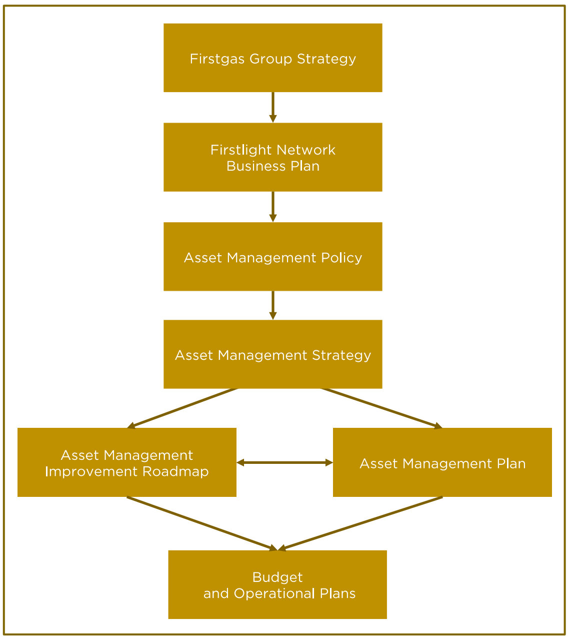
Asset management strategy: The strategy aligns with the Firstgas Group's strategic plan. It provides the direction for the targets, programs and projects included in the asset management plan. The strategy provides the foundation and drivers for the asset management roadmap. The asset management strategy is communicated to the business and stakeholders in various forums.

Asset management improvement roadmap: The roadmap defines how Firstlight intends to improve its asset management maturity and its asset management practices.

Asset management plan: The AMP is a tactical plan that sets out how the network assets will be managed to deliver an agreed standard of services in line with its asset management policy and strategy.

Budget and operational plans: The budgets and operational plans guide the deployment of operational resources to undertake work on the assets and the business. These budgets and plans are aligned to the AMP (or the Network business plan for areas outside of the scope of the AMP).

Figure 22: Key plans and interactions



2.9 Significant Assumptions

Forecasting the future inherently assumes a level of uncertainty. The following assumptions have been summarised below:

Table 4: Significant assumptions

Assumption	Basis	Uncertainty
Escalation of prices 2022 Constant Prices to 2023 Constant Prices	We reviewed all major project and adjusted project costs based on our assessment of the escalation in material and labour costs. For other projects and general expenditure provisions we applied inflation at 6.2% between September 2021 (2022 Constant Prices) and September 2022 (2023 Constant Prices). This data was obtained from Stats.nz.	Actual data was used.
Inflation of nominal forecast expenditure	It has been assumed that the high inflation environment would persist for sometime. Inflation of nominal expenditure forecasts was assumed a 5.5% from FY2024 to FY2025, 5.3% from FY2025 to FY2026, and around 4.0% for each subsequent year.	Inflation in costs may be higher or lower than forecast due to a range of economic factors. Inflation assumptions will be adjusted at each review of the AMP to ensure that reflect the most current economic outlook.
Residential connection and demand growth	Drives the assessment of network constraints, development plans and the timing for development projects.	There is a low uncertainty in relation to residential and commercial growth over the next 2-5 years as land area for development is well known and land

Assumption	Basis	Uncertainty
		development has reasonably long lead-times.
New Zealand's Climate Change Response (Zero Carbon) Amendment Act and associated emissions budget and strategy will increase the demand for electricity	New Zealand's policy direction is to decarbonise industry process heat and transport through electrification. Emissions targets are mandated by the Climate Change Response (Zero carbon) Amendment Act 2019 and these targets will reduce over-time. See assumptions below in relation to demand growth for industrial customers, EV, PV and batteries.	The rate of electricity demand and consumption growth may be greater or less than currently predicted. We will be updating our forecasts on a regular basis to ensure that they remain consistent with current trends and outlook.
Climate change will increase the physical risk exposure to the network	Climate change will increase the intensity and frequency of adverse weather events. Based on recent trends we have increased our forecast expenditure on Service Interruption and Emergencies and on Vegetation Management.	The extent of the physical risk impact to the network and frequency of significant events as a result of climate change is not fully understood. This is an area of further work for subsequent AMPs.
Resource availability	It is assumed that resources will not constrain the ability to complete planned work.	There is a risk that resources will be pulled out of the region to higher paying areas. This could lead to not being able to complete work as planned. There is a risk that we cannot attract contractors into the region to complete planned work.
Availability of materials and equipment	It is assumed that materials and equipment will not constrain an ability to complete planned work. We have adjusted the timing of some projects to account for the longer lead-times for major items of plant.	There is a risk that material availability becomes more constrained due to the network spend in other regions and internationally due to the global electrification trend. We will be reviewing the timing of major projects to ensure they reflect current trends in material availability.
Industrial demand growth—new customers and electrification of process heat	We have allowed a prudent planning margin in our industrial consumption and demand forecasts. This margin allows for the connection of new industrial customers and the electrification of process heat.	There is significant uncertainty in relation to industrial growth. There remains the potential for large new industrial demand, but the timing and size is not yet clear. In this plan we have assessed options for a large new industrial customer, however, expenditure in relation to this work is not included in the forecasts.
Growth in solar PV and batteries	It is assumed that the economics of PVs and batteries will improve and their penetration on the network will increase. PV installations can impact the low voltage network (by overloading transformers, LV circuits or creating voltage instability).	Our forecast for solar PV and batteries are based on Transpower's Te Mauri Hiko forecasts, moderated for socio-economic conditions in Gisborne and Wairoa. Uptake of solar PV and batteries could be faster than we predict which may increase the need for low voltage network reinforcement and controls.

Assumption	Basis	Uncertainty
Growth in EVs	It is assumed that the economics of EVs will improve and their penetration on the network will increase. EVs directly impact the low voltage network (by overloading transformers and LV circuits).	Our forecast for EVs are based on Transpower's Te Mauri Hiko forecasts, moderated for socio-economic conditions in Gisborne and Wairoa. Uptake of EVs could be faster than we predict which may increase the need for network reinforcement and/or localised demand management.
Availability of hotwater demand response	Our demand forecasts current assume that hot water load control will continue to be available. However, our forecast do include ADMD growth (based on historical ADMD growth), which does include some reduction in the hot water control.	It is likely that hot water load control will transfer to load aggregators and will need to be procured through flexibility markets. Our forecasts will be updated in the 2024 AMP to account for this possibility.
Regulatory framework	DPP3 regulatory framework came into effect on 1st April 2020 for 5 years and it is assumed a continuation of the current regulatory settings.	New input methodologies could result in changes to DPP4 which may change the incentives for investment and/or quality targets. Future plans may change as a result.

3. The Network Assets

This section provides an overview of the characteristics and configuration of the Firstlight network that influences the asset management policy and strategy.

3.1 Distribution Area

The network area broadly encompasses the East Cape and Northern Hawkes Bay of New Zealand, covering a combined land area of 11,952 km^2. Firstlight owns and operates an electricity network that includes subtransmission assets (110kV, 50kV & 33kV), distribution assets (11kV), and low voltage reticulation assets (400V/230V) that supply electricity to customers.

The network is separated into two geographical regions generally conforming to the jurisdictions of the Gisborne and Wairoa District Councils.

3.2 Overarching Network Characteristics

Gisborne is the only significant load centre within the network where over 50% of all customers are located. The dispersed nature of other customers means that 89% of the network consists of overhead lines, of which 85% are located in rural or remote rural areas. The large percentage of overhead lines increases the exposure to outages caused by adverse weather events and vegetation.

The network has relatively low levels of subtransmission and zone substation N-1 security.

In addition to Gisborne and Wairoa township, the Network supplies the remotely populated region of the East Coast of the North Island that is among the lowest customer density in New Zealand. Low-density networks typically require a higher level of assets per customer than would be the case for higher-density networks.

All network 11kV distribution feeders are configured radially. Reclosers and sectionalisers are installed to minimise the impact of outages on rural feeders. Firstlight is increasing the number of sectionalisers and reclosers to minimise the impact of outages on its customers.

Like most distribution businesses in New Zealand, the Firstlight network assets are aging. Assets installed in the 1970s are approaching their end of life and are at an increased risk of failure due to end-of-life issues. For Firstlight Network, the ageing asset fleet is more apparent across wood poles and conductors (refer to Section 11.6). Although not currently resulting in high failure rates or materially impacting reliability (refer to Section 6.4), managing the ageing asset fleet is an important focus for the business going forward.

Figure 23: Customer density industry ranking (Source: 2022IDs)

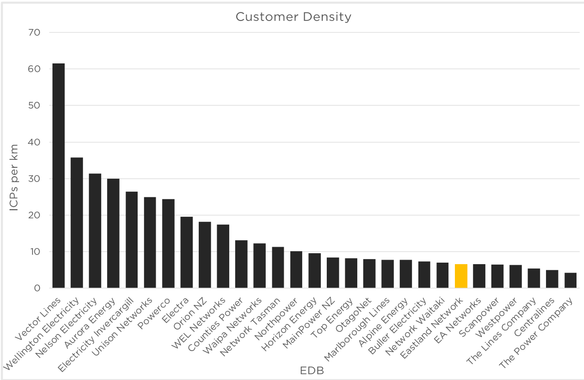


Figure 24: Customers at Firstlight Network (Source: Firstlight analysis)

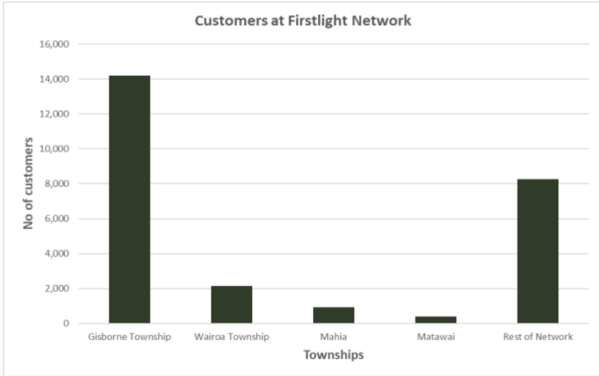


Figure 25: Percentage overhead lines industry ranking (Source: 2020 IDs)

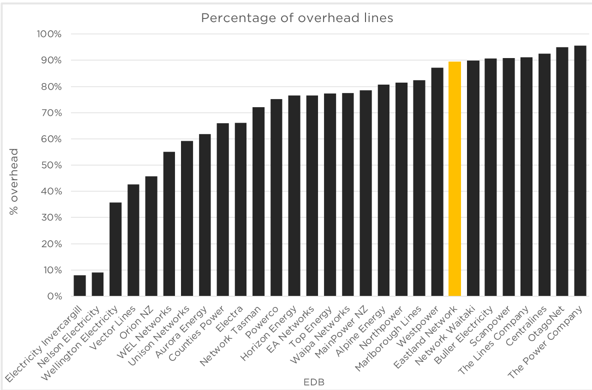
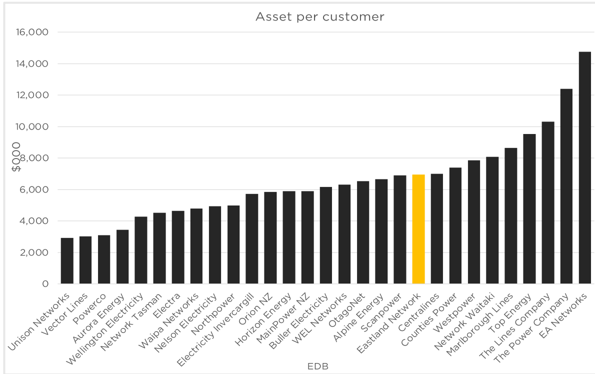


Figure 26: Assets per customer ranking (Source: 2020 IDs)



3.3 Connection to the National Grid

Eastland Network purchased Gisborne and Wairoa's 110kV assets from Transpower in 2015. This consolidated the Grid Exit Point (**"GXP"**) to the Transpower substation at Tuai. The Tuai GXP is located near Lake Waikaremoana and connects the Firstlight network to the transmission grid. The network is supplied from Tuai GXP via four 110kV circuits; two circuits run to Gisborne and two to Wairoa.

3.4 Large Scale Distributed Generation

Generation connected to the network provides additional energy sources to the region and supports the security of supply to zone substations. A summary of the generation assets is shown below:

Table 5: Distributed generation

Name	Owner	Generation type	Size
Te Araroa	Firstlight Network	Diesel	1MW
Ruatoria	Firstlight Network	Diesel	1MW
Tolaga Bay	Firstlight Network	Diesel	1MW
Puha	Firstlight Network	Diesel	1MW
Mahia	Firstlight Network	Diesel	1MW
Waihi	Eastland Generation	Hydro	5MW
Matawai	Southern Generation Ltd	Hydro	2MW

Benefits to the network from operating generators include:

- Providing alternative transmission capacity in the case of a grid emergency;
- Providing localised electricity supply during outages due to faults or planned outages;
- Reducing maximum demand at the Tuai GXP;
- Easing constraints on the subtransmission network (contributing to compliance with planning criteria), thereby avoiding or deferring subtransmission and distribution asset upgrades.

The effect of these benefits is a reduction in overall assets required to supply customers while maintaining reliability.

Firstlight utilises its generator to provide voltage and load support to the network. They are an economical solution to providing an alternative to traditional N-1 zone substation security. They are an effective alternative for remote zone substations where the cost of providing N-1 subtransmission lines is significantly more costly. The generators were crucial in maintaining the electricity supply during Cyclone Gabrielle.

3.5 Subtransmission and Zone Substations

3.5.1 Level of security provided by the subtransmission and zone substation system.

Due to low customer density, the network is afforded relatively low levels of zone substation N-1 security[13]. Approximately 30% of customers are supplied by zone substations with N-1 security, with a further 60% supplied by substations with N-1 generator and N-1 switched security (refer to Figure 27).[14] Adopting these alternative approaches to subtransmission security (the use of generation and automated switching) and using lower-cost overhead construction techniques have afforded the network a modest level of assets per customer compared to other low-density networks (refer to Figure 26).[15] This modest level of assets per customer is key to minimising the impact of the low density on customer prices.

The 110kV subtransmission protection schemes are all coordinated with Transpower to ensure they operate correctly.

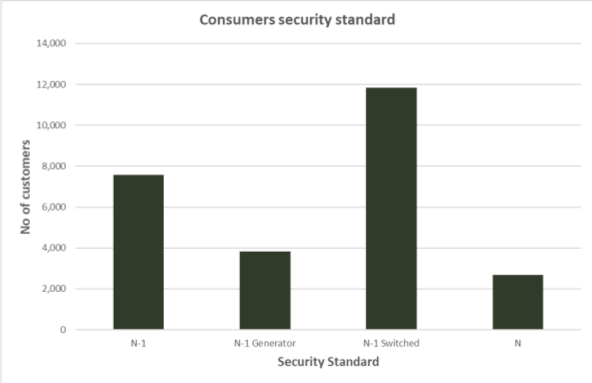
The protection functions for the 50kV and 33kV lines are all standard in terms of protection types (overcurrent, earth fault, etc.). However, we are examining communication options and developments within the Gisborne Township to create a closed loop circuit for the Carnarvon – Kaiti line, which will assist in minimising outage times and areas.

[13] N-1 security is typical for substations on higher density networks.

[14] In terms of security standards, N-1 means that the loss of a single subtransmission line or zone substation transformer will not result in the interruption of supply. That is, there is redundancy within the supply system. N-1 Generator means that supply will be briefly interrupted while the generator starts and comes online. N-1 Switches means supply will be briefly interrupted while supply is switched to an alternative source (typically an adjacent substation). N security means supply will be interrupted and not restored until repairs are made.

[15] Similarly low-density networks are OtagoNet, The Power Company, Centralines, The Lines Company, Westpower, EA Networks, Scanpower, Marlborough Lines, Mainpower, and Top Energy. Almost all of these companies have a higher level of assets employed per customer than our network.

Figure 27: Customer substation security ranking



3.5.2 Subtransmission system

The network comprises 110kV, 50kV and 33kV subtransmission circuits.

The 110kV subtransmission system connects the Gisborne and Wairoa substations to the Tuai GXP via four 110kV circuits. Two 110kV circuits run to Wairoa and two to Gisborne. The lines are a mix of steel towers and poles. The 110kV double circuit lines are N-1 electrically but not N-1 mechanically, with the circuits sharing some poles and towers.

The 50kV subtransmission system begins at the Gisborne substation and supplies all of Gisborne's zone substations via four lines (Carnarvon, Puha, Kaiti and Makaraka). The East Coast line (a spur of the Kaiti line) is the only spur line on the subtransmission system. It supplies Tolaga Bay, Tokomaru Bay, Ruatoria and Te Araroa zone substations. This line is a focus for current maintenance and replacement programs. A 110kV tower line runs from Gisborne to Tokomaru Bay, which has been reconfigured to operate at 50kV and provide N-1 Switched security to Tokomaru Bay. Three 1 MW diesel generators have been placed at Tolaga Bay, Ruatoria and Te Araroa to support security during planned and unplanned outages.

Positioned between the Carnarvon and Port substation is the only section of subtransmission line that runs underwater. This cable was laid in 2005 and is a critical line section providing security to most of the Gisborne township. Regular thermal imaging inspections are performed on the cable terminations to ensure the integrity is not compromised at the joints. A short cable section is laid under the southern approach to the Gisborne Airport. The high cost of subtransmission cabling has limited further undergrounding of the subtransmission system.

There is a 50kV line that connects Eastland Generation's Waihi 5MW hydro-generating plant to the Wairoa network. Waihi Hydro can reduce the maximum demand at the Wairoa substation. The Wairoa substation has a firm capacity of 10 MVA. The Waihi Hydro plant can be called upon if generation support is required during periods of high load.

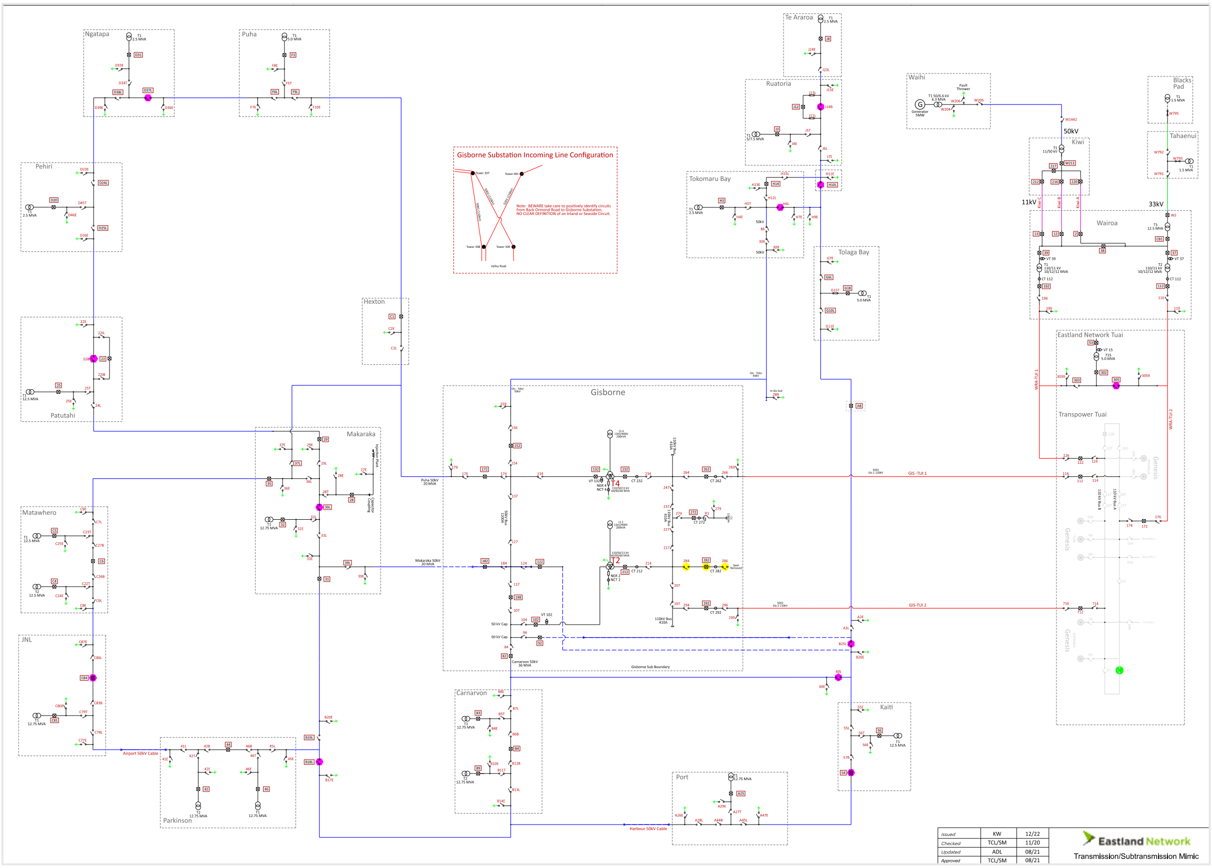
The Wairoa subtransmission system operates at 33kV and supplies the Nuhaka and Mahia townships from the Wairoa substation. The line runs from Wairoa to the Tahaenui substation and the Blacks Pad substation. The 33kV line (originally operated at 50kV) was built in 1972 and runs over the hilltops between Wairoa and Nuhaka, making it difficult to access in winter. Extreme weather events or insulator failures typically cause unplanned outages on this line.

Blacks Pad, which is at the end of the subtransmission line, is located 20km from the main load centre for the area. This creates security of supply challenges for the Mahia area. One diesel generator is located close to the Mahia township, supporting additional load during the summer demand peaks.

3.5.3 Zone substations

Figure 20 shows the Tuai GXP, Gisborne and Wairoa zone substations (110 kV to 50/33 kV) and the subsidiary zone substations (50/33 kV to 11 kV)

Figure 28: Firstlight Network zone substation mimic



Firstlight Network has 21 zone substations with three main operational functions:

- Receiving the 110kV supply into Gisborne and Wairoa, converting the voltage from 110kV to 50kV or 33kV, and supplying the regional 50kV and 33kV subtransmission systems;
- Receiving the subtransmission supply, converting the voltage from 50kV and 33kV to 11kV, and supplying the distribution network via distribution feeders;
- Providing an injection point for local generation;

The main assets associated with these zone substations include power transformers, switchgear (subtransmission and distribution), protection relays, SCADA, and buildings that house the equipment.

Zone substations are critical assets for the network as they are the central hubs of supply for urban areas, rural townships, and the wider rural areas. These assets are inspected and maintained appropriately to minimise the risk of unplanned outages occurring. The forecast health of some assets indicates that replacements will be required within the planning period (See section 11).

Firstlight utilises mobile buildings (typically *Portacom*) as switch rooms for substations. This decreases the time required for switchgear replacement, with the construction completed off-site before installation. Replacement typically involves swapping the entire switch room, considerably reducing the complexity and cost risk.

3.5.4 Generators

The network employs five stationary diesel generators connected to the 11kV distribution network. The generators and ancillary control systems are typically installed in repurposed shipping containers, reducing the complexity and cost risk during installation.

Eastland Generation Limited initially owned the stationary generator fleet. Firstgas Group purchased the generators at the time Eastland Network was acquired.

Figure 21: Firstlight Network embedded generation

The generators form a critical part of the distribution system, providing customer supply during planned/unplanned outages and for voltage support under high load conditions.

3.6 Distribution Network

3.6.1 Configuration and security

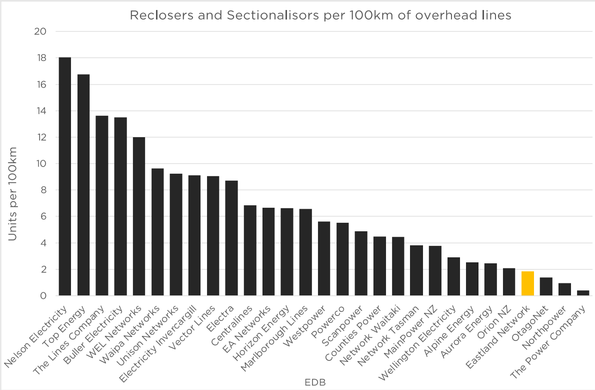
All 11kV distribution feeders are configured radially with switches used to sectionalise or reconfigure the line during faults or planned outages. The switches are a mix of load-breaking (air-break switches and ground mount switchgear), line reclosers, sectionalisers, and drop-out fuses. There are typically interconnecting switches between feeders, although these can be sparse on long rural feeders.

For long rural feeders, reclosers, sectionalisers, and drop-out fuses are installed to isolate the faulted section of the line and minimise the impact of outages. The network currently has a relatively low density of reclosers (refer to Figure 29) and further installation of remote switchgear is planned to sectionalise the network further.

Two sets of fault locators are primarily used for faults that are difficult to locate, such as insulator failures or intermittent faults. The network loads on rural feeders are sometimes too small for detection by existing locators due to the technology at the time being limited to a 5A supply.

There are now more efficient locators that operate at much smaller current ratings, and the acquisition of these units in the coming years will be investigated.

Figure 29: Recloser and Sectionaliser Density



3.6.2 Overhead distribution system

The overhead distribution system transports electricity from the zone substation to distribution transformers in small townships, and rural and remote rural areas. The average overhead rural feeder is 62 km long, supplying approximately 212 customers. There are seven feeders over 100 km long that supply remote areas of the network.

3.6.3 Underground distribution system

The underground distribution system transports electricity from the zone substation to distribution transformers in urban areas. The underground distribution system is typically installed within urban areas where public safety is a factor, and local councils require underground lines. PILC and XLPE cable comprise a significant proportion of the network's underground cabling.

The distribution switchgear associated with the underground distribution network is predominantly ground-mounted and is used to sectionalise or reconfigure the network during faults and planned outages. The underground system is typically well interconnected with adjacent feeders with a switch density of approximately one switch for every 500m of underground cable.

3.6.4 Distribution transformers

Distribution transformers connected to the overhead network are primarily pole-mounted. Due to physical limitations (pole mechanical loading), the pole-mounted transformers are typically 50kVA or less.

The installation of ground-mounted distribution transformers increased in the early 2000s primarily to reduce public safety risk and to support load growth in urban areas (before 2000, large distribution transformers were mounted on two pole structures that had reduced clearance to the ground). During the early to mid-2000s, large sections of the urban overhead network were converted to underground. These conversions improved public safety, reliability, public image, and regulatory compliance.

Renewal of some of the original township transformers due to the condition of their enclosures, has been a focus for the fleet plan, this has largely been completed. There is however there is an ongoing need to continue to maintain the fleet, and forms part of the general maintenance and overhaul planned expenditure.

Table 6: Composition of distribution transformer fleet

Eastland Network owned	Pole mounted transformers		Ground mounted transformers	
Size	<= 100kVA	> 100kVA	<=100kVA	>100kVA

Eastland Network owned	Pole mounted transformers		Ground mounted transformers	
% overall transformer count	85.0%	0.2%	2.9%	11.9%
% Rural	82.5%	0.1%	1.9%	1.9%
%Urban	2.6%	0.1%	0.9%	10.0%

3.6.5 Voltage Regulators

Voltage regulators are used on the rural network to support the voltage on long rural feeders. Where possible, the feeder conductor is sized to reduce voltage drop to keep the use of voltage regulators to a minimum. Voltage regulators are also used to increase the capacity of feeders that are used to back up small zone substations. These backup feeders support the small zone substation during subtransmission and zone substation maintenance.

Voltage regulators are placed in the following areas:

Table 7: Voltage regulator locations

Feeder	Length (km)	Purpose	Install Date
Te Arai feeder	103	Assist voltage constraint on long line feeder	1964
Kanakanaia feeder	53	Assist voltage constraint on long line feeder	1964
Matawai feeder	271	Assist voltage constraint on long line feeder	1964
Muriwai feeder	98	Assist voltage constraint on long line feeder	1980
Inland feeder	119[16]	Assist voltage constraint when connecting through to Ruatoria substation. Provides synchronous voltage to the generator at Ruatoria Substation.	1984
Dalton feeder	130	Assist voltage constraint on long line feeder	1985
Ngatapa substation	n/a	Assist voltage constraint when Tx or sub out for maintenance or unplanned outage	2012
Pehiri substation	n/a	Assist voltage constraint when Tx or sub out for maintenance or unplanned outage	1965
Raupunga feeder	266	Assist voltage constraint on long line feeder	2001
Mahia feeder	139	Assist voltage constraint on long line feeder	1965
Mahia SWER line	n/a	Assist voltage constraint on long line feeder	2005

3.6.6 Low voltage system

The low voltage network is supplied from our distribution substations. The nominal voltage is 230V for a single-phase connection and 400V for a two or three-phase connection. Low voltage supply can be single, two, or three phases depending on the customer's requirements. The meshing of the low voltage network is only possible in the Gisborne and Wairoa townships and is generally only used to restore power during faults.

Some customers own the power poles on their property. Land ownership changes have created problems where some customers are unaware of their responsibilities to maintain the power poles on their property. We are currently considering how to address this emerging issue.

3.7 SCADA Communications and Control

SCADA is used for monitoring and controlling the network. The SCADA system consists of various sensors and control relays, remote terminal units (**RTUs**) at remote sites, and a masterstation in the Control Room.

[16] Length used is when the Makarika and Inland feeders are joined

Frequency, voltage, current, and temperature information is obtained from the sensors and relays and displayed in real-time on the SCADA masterstation. The information alerts operations staff of abnormal conditions and assists with operational decision-making.

Historical information is stored at 30-minute intervals and is used to communicate load trends for planning and reporting.

A backup Control Room and SCADA masterstation are installed at the Gisborne substation. The site has a backup generator supply, communications, data storage, and control terminal.

Several communications links (VHF radio, UHF radio, copper cable, fibre cable) and protocols provide data between the RTU and the masterstation. These links also provide voice communication between field staff and the Control Room. Data communication is via IP and RS232/485 serial. There is communication path redundancy between the RTU and the masterstation.

A substation management system complements the SCADA system. This system allows access to intelligent devices (such as numerical protection relays) to fine-tune configurations and operating parameters or retrieve detailed event logs. The system uses an IP-based communications network established using in-house and third-party communication links.

Seven radio huts are used across the region to support the communication network, which assist with communication to devices in rural areas. These sites all have backup diesel generators and are critical for the SCADA system and voice communication with field staff.

4. The Operating Context

This section presents a view of the key operating and network issues that are drivers of the asset management policy and strategy.

4.1 Overview

The operating context and network issues are important matters that shape the asset management policy and strategy. These issues remain similar to those identified in our 2020 and 2021 AMPs; however, progress has been made in response to many of the issues, which are discussed in later sections of the AMP. We have included a new context issue concerning balancing the three limbs of the energy trilemma. This issue has gained greater importance due to the increasing need for higher opex and capex to respond to the issues mentioned below.

The policy and strategy need to respond to, and be consistent with, the context of the network and aligned with Firstgas Group's strategy.

In this section, we discuss the important context issues, including:

- Our historical focus on minimising distribution prices to one of the lowest socio-economic regions of New Zealand;
- Notwithstanding the reliability challenges we face; we continue to deliver a level of service that meets customers' expectations;
- We have a small and static industrial customer base;
- We have implemented alternatives to lines to deliver security at the least cost;
- The economies of scale benefits from Firstgas Group;
- Our subtransmission and distribution assets are aging, but the asset health remains appropriate;
- The increasing impact of climate change on extreme weather events, including ex-tropical cyclone Hale and cyclone Gabrielle;
- The increasing pace of energy transformation;
- There is an emerging risk of capacity constraints into Gisborne due to demand growth from new industrial load, electrification of transport and electrification of process heat;
- We need to communicate how we intend to balance the energy trilemma.

In the 2021 AMP, we identified the quality of asset information as a context issue. This has now been removed. We have been improving the quality of asset information since 2020. While work remains ongoing, we are comfortable that the quality of the asset information for our key asset classes is appropriate. We have provided an update on how the data has improved in Section 4.12.

4.2 Our historical focus on minimising distribution prices to one of the lowest socio-economic regions of New Zealand

Firstlight network supplies one of the lowest socio-economic regions[17] (refer to Figure 30), which means that customer's ability to pay high electricity prices is limited. The average consumption by customers is amongst the lowest in the country, reflecting the low socio-economic circumstances for customers and the absence of a large industrial customer base (refer to Figure 31).

[17] Measured based on the deprival index with dark red areas in Figure 30 representing the most deprived areas.

Firstlight has sought to minimise its investment in assets and operating costs to keep costs to customers as low as possible. This has been successful, and Firstlight has achieved a compounding annual growth rate (**CAGR**) for distribution costs per customer of 0.1% p.a. over the past ten years (refer to Figure 32).

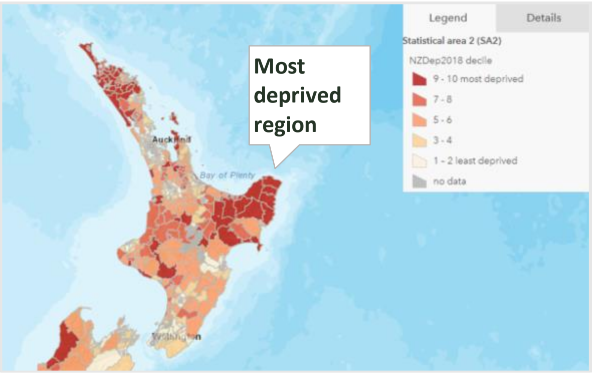


Figure 30: NZ regional deprivation profile (Source: Environmental Health Intelligence NZ; Massey University)

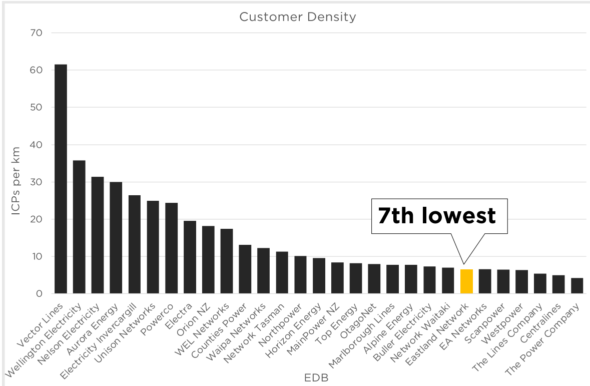


Figure 31: Average consumption per ICP (Source IDs)

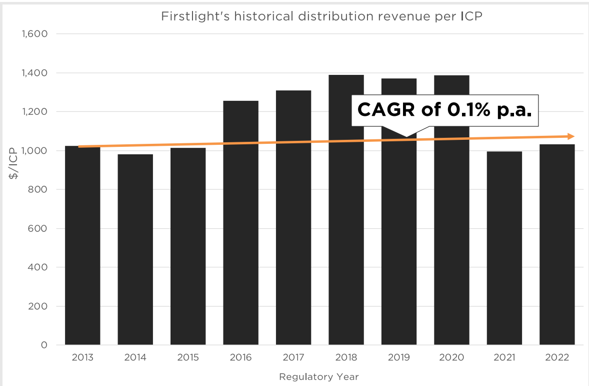


Figure 32: Historical average distribution price (Source: IDs)

4.3 Notwithstanding the reliability challenges we face, we continue to deliver a level of service that meets customers' expectations

Managing network reliability has been difficult, and the underlying[18] reliability performance has been largely static and shows no observable improvement (refer to Section 4.8). The RAW reliability (before normalising for major events) has been highly volatile, reflecting the impacts of adverse weather events and other major events (e.g. the loss of the 110kV lines to Gisborne in RY2017 following a plane crash).

Notwithstanding these reliability challenges, customers have consistently indicated they are generally satisfied with the level of service received from Firstlight, with 80% of customers rating service between good and excellent (refer to Figure 33). The customer survey results are further detailed in Section 6.3 Customer Survey.

[18] After normalisation for major events as per the regulatory quality standards.

Figure 33: Customer satisfaction (Source: Firstlight)

4.4 We have a small and static industrial customer base

We have a small number of industrial customers linked to the region's primary production. Our large customers are predominantly timber and food processing facilities. There are several significant processing and storage installations on the western outskirts of Gisborne, clustered in the Gisborne industrial estate, the Gisborne Port area. There is one meat processing plant in Wairoa.

The industrial customer base has not materially changed over the past decade.

Table 8: Firstlight Network – Large Industrial Customers

Company	Industry	Region	Demand
Juken NZ Limited	Timber Processing	Gisborne	2 MW
Affco	Meat Processing	Wairoa	4MW
Leaderbrand	Food Processing	Gisborne	2 MW
Ovation	Meat Processing	Gisborne	2 MW
Tairāwhiti Healthcare	Health Care Provider	Gisborne	2 MW
Cedenco	Food Processing	Gisborne	2 MW
Far East Sawmill	Timber Processing	Gisborne	2 MW

The nature and size of the operations carried out by these industries do not significantly impact the network at an individual level. However, the combined consumption of these companies is 15% of the total energy conveyed and 25% of the total demand. Direct contact is maintained with these companies to assess their needs and the adequacy of current service levels.

There are currently no known issues associated with the operations of these companies, indicating changes in demand are not expected to significantly impact the network over the planning period. However, an emerging issue is the increasing requirement for continuity of supply, improved restoration times and less flicker and sag. There is also the potential for increased process heat related electricity demand.

Firstlight will regularly engage with customers on all manners of business and common interests with an external advisor formally consulting with the 25 largest customers (by energy consumption), specifically on the issue of price and supply quality, and this is discussed further in Section 8.3.1.

4.5 We have implemented alternatives to lines to deliver security at least cost.

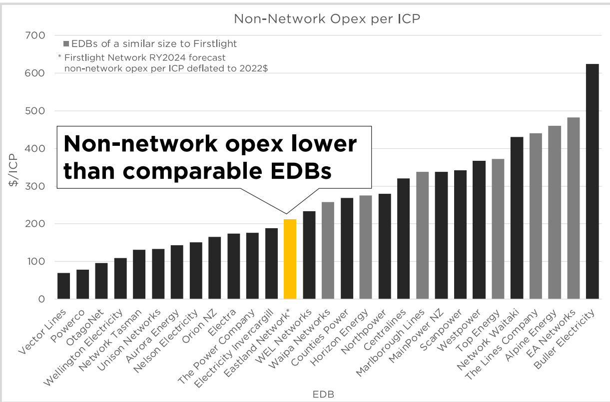
Given our large rural network area with significant distances between rural and coastal communities, it would be costly to provide security by having redundancy in subtransmission lines and zone substation transformers. Instead, we have provided appropriate network security using lower-cost generation alternatives. These are described in section 3

Our distribution network comprises radial feeders with limited interconnection for backup supply in case of a fault or planned outages. Due to the few customers connected to these feeders, building lines to increase interconnection between feeders would not be cost-effective. Our approach to managing network security in rural areas is to utilise mobile generators (typically with a maximum capacity of 300kVA) to support the network during faults that cannot be restored within the required time and during large, planned outages.

4.6 The economies of scale benefits from Firstgas Group

Historically, the network and its customers benefited significantly from the economies of scope from being part of the Eastland Group. With the recent acquisition by Firstgas Group, those economies are expected to continue. Figure 34 shows that Firstlight's FY2024 forecast non-network opex is lower (more efficient) than all similar-sized EDBs.[19]

Figure 34: Overhead cost, industry rankings (Source: 2022 IDs and Firstlight Forecasts)



4.7 Our subtransmission and distribution assets are aging, but the asset health remains appropriate

Like most distribution businesses in New Zealand, our assets are ageing. An increasing number of assets installed in the 1960s, 1970s and 1980s have reached the onset of unreliability (**OOU**) and are approaching their maximum practical life (**MPL**). This means there is an increasing risk of failure due to end-of-life issues that must be managed.

The ageing asset fleet is more apparent across wood poles, conductors, zone substation transformers, and distribution overhead switchgear (refer to Figure 35 and the asset fleet plans included in Section 11).

Asset age is not the only consideration in determining the overall asset health of an asset, but one of the factors used to determine the overall asset health. Notwithstanding the aging fleet, the health of our key distribution assets is generally consistent with the industry. Our wood poles[20],

[19] The non-network opex per ICP shown is the RY2024 forecast for Firstlight Network, deflated to 2022$. Electricity Invercargill (managed by PowerNet) and Nelson Electricity (managed by Network Tasman and Marlborough Lines) are smaller than Firstlight with lower non-network opex but are managed by larger EDBs.

[20] This include subtransmission, distribution and LV pole.

concrete poles[20], switches and fuses, conductors and reclosers have fewer low-health assets than the industry. Firstlight's pole mount transformer fleet has lower health than the industry.

The ageing asset fleet has not resulted in high defective equipment failure rates (refer to the performance review in Section 6.5). However, managing the ageing asset fleet will continue to be a focus for the business going forward.

Figure 35: Distribution Asset Age Profile (Source: 2022 IDs)

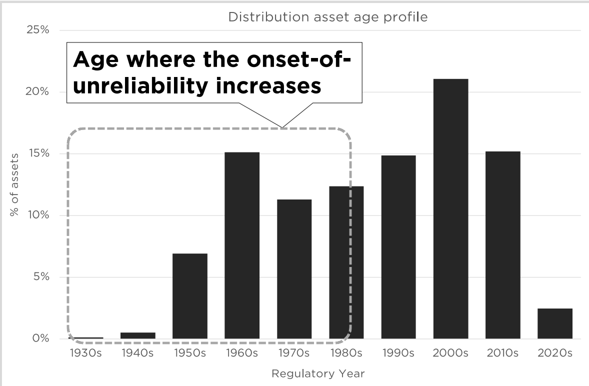
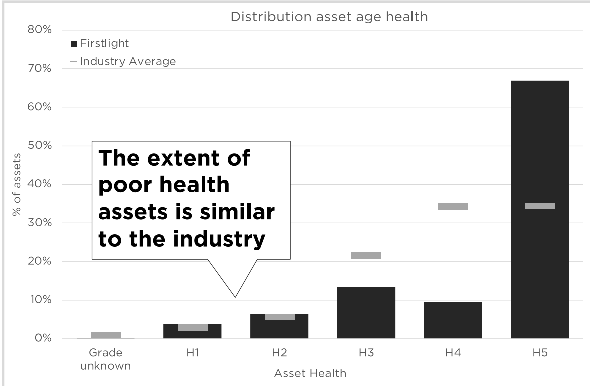


Figure 36: Distribution Asset Health Profile (Source: 2022 and 2023 IDs)[21]



4.8 The increasing impact of climate change on extreme weather events, including ex-tropical cyclone Hale and cyclone Gabrielle

The East Coast and Wairoa regions are increasingly being impacted by extreme weather. During RY2023, we experienced 44 days of extreme weather (MetService red and orange events), up from an average of 25 per year for the prior three years (refer to Figure 37). Rainfall increased materially over RY2023 and was 50% higher than the average of the preceding three years (refer to Figure 38).

Ex-tropical cyclone Hale and cyclone Gabrielle severely impacted the region. Most of the network performed very well during these events; however, the infrastructure was severely damaged in some areas, and our network was no exception. Due to the damage to roading and our network, it took us more than two weeks to restore supply to a few isolated customers following the cyclone events.

[21] This includes wood poles, concrete poles, switches and fuses, conductor, reclosers and sectionalisers, and pole mount transformer fleets. Wood poles and concrete poles includes subtransmission, distribution and LV poles.

Figure 37: Extreme Weather Days (Source: Metservice)

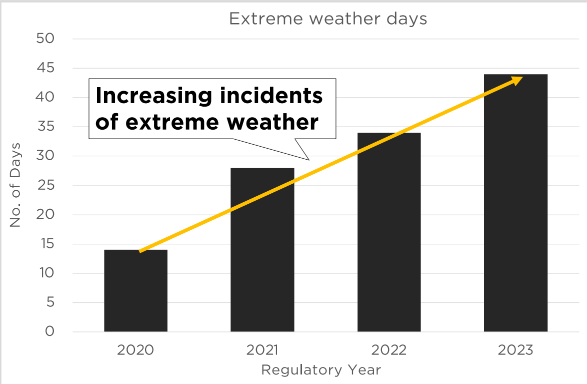
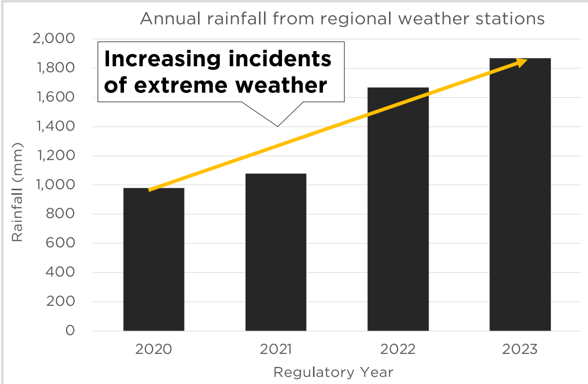


Figure 38: Annual Rainfall (Source: Metservice)



The increase in extreme weather has caused an increase in adverse weather[22], adverse environment[23], and vegetation outages. Adverse weather, adverse environment, and vegetation outages (during extreme weather) accounted for 84% of RAW SAIDI during RY2023 (refer to Figure 39).

During extreme weather events, vegetation outages are predominantly caused by trees outside the growth limit (refer to Section 6.4 for further details). The growth limit is the areas around the lines where Firstlight can trim the trees. A contributing factor to the extent of vegetation-related outages is the network's exposure to forestry plantations, with approximately 7% of subtransmission lines and 10% of distribution lines passing through forestry areas.

The increasing occurrence of cyclonic conditions is concerning. During cyclone Gabrielle, high winds were the most significant cause of asset damage to overhead lines (recorded as adverse weather events). The windspeeds experienced during Cyclone Gabrielle were very close to current line design limits, and the windspeeds in some locations were likely above the design limits for older (pre-2000) poles.

Most (but not all) adverse weather, adverse environment, and vegetation outages (during extreme weather) occur during major events (**MEs**)[24]. However, the ME process is not perfect; some extreme weather events do not result in MEs, and "spillover"[25] outages occur following MEs. The result is that normalise (post ME) SAIDI is increasing (refer to Figure 40), which resulted in a breach of the regulated quality cap in RY2023 and is reducing the "headroom" to the cap more generally.

22 These are network equipment faults and failures caused by extreme weather events. The faults or failures are typically caused when the weather conditions are above the equipment's design limits.

23 These are outages caused by floods and landslips.

24 Major events (MEs) are 24-hour periods where the network experiences events that result in SAIDI and SAIFI above a set boundary limit. For Firstlight, the limit is 13.1 SAIDI and 0.177 SAIFI (from FY2021). The purpose of MEs is to reveal the underlying reliability performance by removing the impact of ME.

25 These are outages that occur the day following an extreme weather day. It is generally recognised that damage can occur during extreme weather days, but the asset does not fail until some time after the event.

Figure 39: Adverse Weather, Environment and Vegetation Impact (Source IDs, RAW SAIDI)

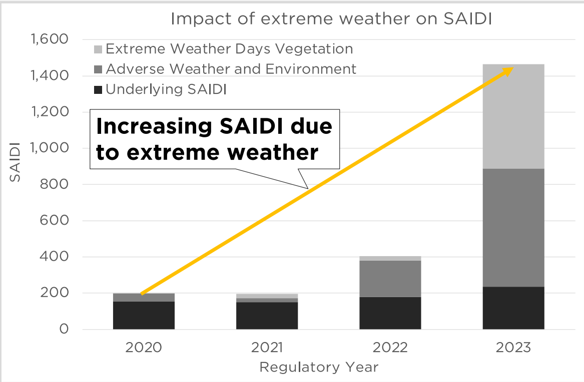
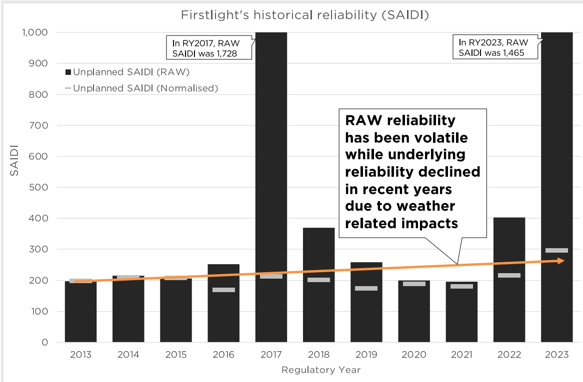


Figure 40: Historical network reliability (Source: IDs, RAW SAIDI)



In response to the increasing impact of climate change on extreme weather events, we are enhancing our resilience strategy (refer to Section 11).

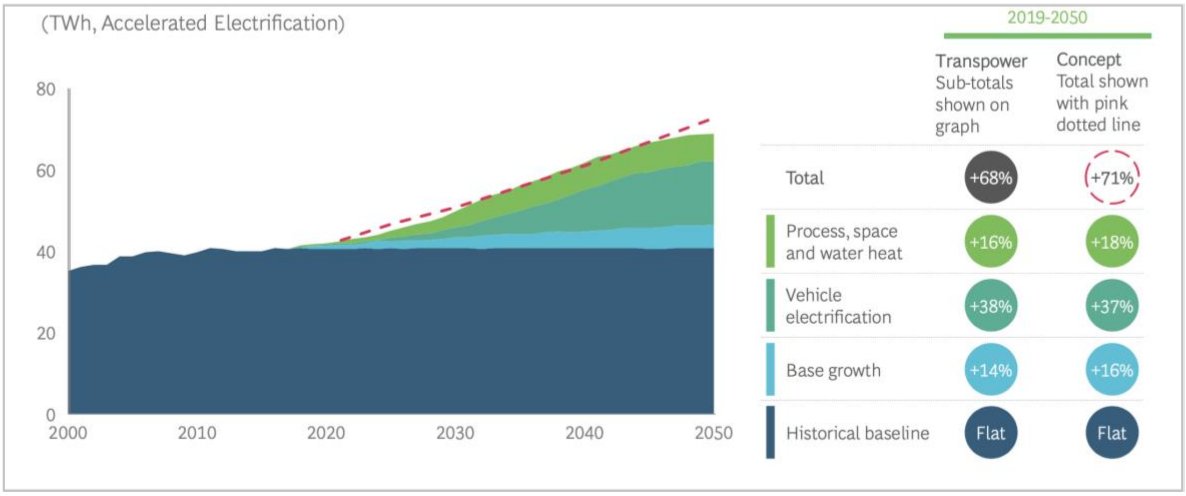
4.9 The increasing pace of energy transformation

The Climate Change Commission's ("**CCC**") final advice to the Government in 2021 advocated a pathway to net-zero 2050 that focused on reducing emissions through electrification and increasing renewable generation. The basis of the CCC's demonstration pathway for the energy sector were:

- Accelerating the uptake of electric and other zero-emissions cars, buses and trucks;
- Continuing to improve the thermal efficiency of buildings;
- Shifting from fossil gas heating systems in buildings to biomass and electricity;
- Replacing coal-based industrial heat with biomass and electricity, and from 2031, replacing fossil gas with biomass and electricity;
- Developing a national energy strategy.

On Firstlight's network, the energy transformation will be seen through an increase in the installation of small-scale distributed generation ("**SSDG**"), an increasing uptake of electric vehicles ("**EVs**"), the electrification of natural gas and LPG, and the electrification of process heat. At a national level, gross electricity consumption is forecast to increase by 71% by 2050 (refer to Figure 41). Due to regional factors (i.e. socio-economic factors and large rural communities), the rate of transformation across our network will likely lag behind some other areas, particularly urban centres like Auckland, Wellington and Christchurch.

Figure 41: Forecast Growth in Electricity Consumption (Source: BSC Report[26], Exhibit 23)



Actions by the Government have accelerated EV uptake (refer to Figure 42), and the improving economics of EVs is likely to accelerate their use further (refer to Figure 43). Our demand forecast needs to consider this growth.

Figure 42: Electric Vehicle Uptake (Source: BSC Report, Exhibit 20)

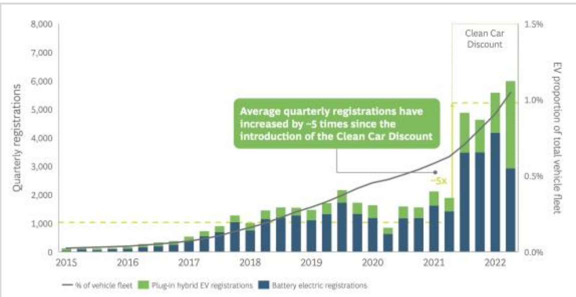
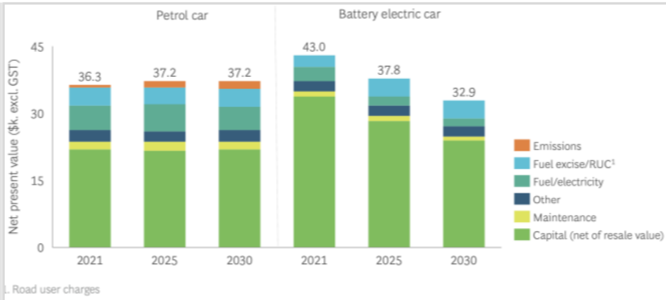


Figure 43: Electric Vehicle Economics (Source: BSC Report, Exhibit 21)



In terms of demand, growth in EVs will have the largest impact on the network. BCG's modelling forecasts peak demand will increase by 28% by 2030 and 93% by 2050 before EV smart charging and demand response contributions.[26] This level of demand growth is significant and above what is presently forecast by us. The key to avoiding demand growth of the magnitude suggested by BCG is demand response, including via hot water control and EV charging demand response (i.e. flexibility). Our current demand forecasts assume continued access to hot water demand response (albeit reducing) and EV charging occurring at off-peak times (i.e. responding to pricing signals). The Electricity Authority (**EA**) is working to develop the flexibility market to enable demand response.[27]

In Section 10.4, the impact of the energy transformation on demand and consumption has been forecast over the next 20 years. These forecasts are based on Transpower's *Whakamana i te Mauri Hiko* report[28] (adjusted for Firstlight Network's socio-economic circumstances).

Section 10.4 outlines the potential implication of the increasing pace of the energy transformation and how Firstlight is considering responding to these challenges. This work is still in formation and will be further developed over the following two AMPs.

There is the potential for demand growth to be higher than we currently forecast. The implications of higher growth will be increased network development, faster adoption of non-network

26 Boston Consulting Group, "The future Is Electric, A Decarbonisation Roadmap for New Zealand's Electricity Sector", October 2022.
27 https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/
28 https://www.transpower.co.nz/resources/whakamana-i-te-mauri-hiko-empowering-our-energy-future.

solutions, or the requirement to procure greater flexibility. This will have opex and capex implications.

4.10 There is an emerging risk of capacity constraints into Gisborne due to demand growth from new industrial load, electrification of transport and electrification of process heat

The 110kV lines supplying Gisborne are rated at 55.5MW, with current net peak demand close to 50.5MW[29]. The current spare capacity is sufficient for organic growth but insufficient for large new industrial loads and the electrification of transport and process heat over the medium term.

It is prudent for the network to be prepared for new electrification load and to have capacity available for a large-scale industrial load growth to support regional economic growth. This preparation work is covered in Section 10.

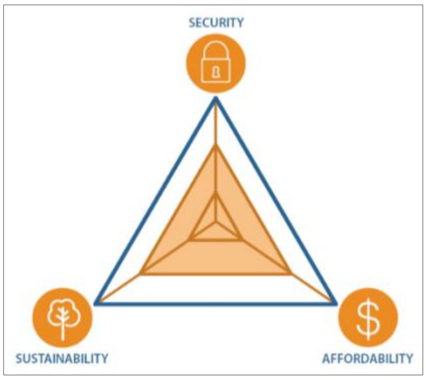
4.11 We need to communicate how we intend to balance the energy trilemma

At Firstgas Group our mission is "safely and reliably delivering energy that is affordable and acceptable to New Zealand's families and businesses".

Managing an electricity distribution network requires the balancing of a range of factors. Ensuring our services are affordable, investing to ensure our network is secure and resilient, and supporting New Zealand's decarbonisation efforts are material issues for Firstlight.

The importance of this balance has increased for Firstlight due to the growing need for higher opex and capex to respond to our aging asset fleet, improve resilience, and support the electrification of transport and process heat.

Figure 44: The energy trilemma



The Energy Trilemma[30] is a well-recognised framework (refer to Figure 44) for strategic optimisation in the energy sector. This framework has been adopted throughout the energy sector to communicate how these factors are being balanced.

We believe that it is important to communicate and consult with stakeholders about how we are thinking about balancing the energy trilemma and what this could mean for our customers.

In Section 7.5, we discuss how we are thinking about balancing these factors.

4.12 Improvements in data quality

We have been improving the quality of asset information since 2020. The goal is to have all asset classes at a data quality rating of at least 3 by the end of RY2025 (concerning age, quantity and health). While work remains ongoing, we are comfortable that the quality of the asset information for our key asset classes[31] is appropriate.

We have completed field surveys for many key asset classes and expect to complete the remainder over the next two years.

[29] Winter line rating and winter peak demand. Winter peak demand is after netting off 4.4MW of generation. Gross peak demand was 54.9MW.

[30] Source: World Energy Council.

[31] Power transformers, substation switchgear, distribution (11kV) GM transformers and distribution switchgear, overhead structures, and conductor.

As part of the asset management roadmap, the DNO Common Asset Indices Methodology was adopted to determine the health of assets. The improvements to asset health data accuracy reflect the application of the DNO Methodology and the revised accuracy ratings of asset age data.

The improvements in the data quality since the RY2019 disclosures are shown in Table 9 below.

Table 9: Changes in Data Quality

Asset class	2019 ID Data accuracy rating (schedule 9a, 9b, 12a)	2023 Data accuracy rating		
		Asset attributes and quantity (schedule 9a)	Asset age (schedule 9b)	Asset health (schedule 12a)
Zone Substation Transformers	1	4	4	4
Zone substation 3.3/6.6/11/22kV GM Circuit breakers	1	4	3	3
Concrete poles	1	3	2	3
Wood poles	1	3	2	2
Distribution open wire conductor	1	1	1	1
Distribution 3.3/6.6/11/22kV Switches and Fuses (pole mounted)	1	2	2	2
Distribution 3.3/6.6/11/22kV GM Switchgear	1	4	3	3
Distribution 3.3/6.6/11/22kV RMU	1	2	2	3
GM Transformer	1	4	2/3[32]	3
PM Transformer	1	2	2	3
Voltage regulators	1	3	3	3

Following the acquisition by Firstgas Group, asset data was transferred to Esri and Maximo (IBM Maximo Asset Management). These systems are fully architected for data security and quality processes. Asset attribute, age, and health data are held within Maximo (a single source of truth). Spatial attribution to support mapping is stored in Esri.

Asset information systems are further detailed in Section 9.

[32] 2 for Wairoa region. 3 for Gisborne.

5. Firstgas Group Strategy and Stakeholders

This section describes how Firstgas Group's strategy and stakeholders aligns with the asset management strategy.

5.1 Firstgas Group Vision and Mission

Firstlight is a team of people who, with its contractors, are responsible for keeping the lights on across 12,000 square kilometres of the East Coast. Firstgas Group has a strong focus on sustainability, planning for new energy opportunities, and ensuring that Firstlight can continue to deliver a reliable service.

Firstgas Group is governed by its vision and mission statements, which are:

- Proudly leading the delivery of New Zealand's energy needs in a changing world.
- Safely and reliably delivering energy that is affordable and acceptable to New Zealand's families and businesses.

Firstlight Network is committed to providing services that meet customers' needs and supporting the growth and prosperity of the Tairāwhiti and Wairoa regions.

5.2 Firstlight Network's Health and Safety Policy

Firstgas Group is committed to providing and maintaining a safe and healthy environment for all its employees, contractors, customers, and the public. Firstgas is committed to ensuring that health and safety and the inherent risks associated with electricity are appropriately managed.

Table 10 states the Health and Safety Policy that is currently applied to Firstlight. This policy was developed by Eastland Group and remains in effect until Firstgas Group has the opportunity to review it and ensure it aligns to Firstgas' objectives and strategies. This will be completed during CY2023.

Table 10: - Health & Safety Policy

Together we achieve safe, healthy and enjoyable workplace environments through:

- Compliance with our obligations under all relevant legislation and regulations, as well as company operational policies, standards, plans and procedures;
- Development, communication and monitoring of measurable health and safety objectives and performance standards in all work areas;
- Resourcing health and safety activities and initiatives;
- Maintaining facilities, plants and equipment in safe condition;
- Ensuring hazardous substances and materials are safely managed across their lifecycle;
- Provision of appropriate health, safety and environmental training, supervision, and resources to workers;
- Ensuring our workers know their safety responsibilities and have the tools, capability, information and resources to maintain a safe and healthy environment;
- Identifying critical risks that exist in each business sector that arise as a result of our operations, environment, or equipment and taking appropriate steps to eliminate or minimise these;

- Monitoring and reporting on critical risks and the effectiveness of the relevant controls;
- Recognising additional hazards and managing the risks associated with operating major hazard facilities;
- Informing workers, third parties, visitors and the public of these hazards/risks and impacts that may cause potential harm to people, our business and/or our environment;
- Promoting safety reporting processes which support workers to raise safety concerns;
- Completion of accurate investigations into all reported incidents, injuries and near misses and sharing the learnings with all stakeholders to reduce the likelihood of reoccurrence;
- Ensuring that continual improvement occurs through ongoing engagement and participation opportunities with workers and communication, consultation and coordination with key stakeholders and third parties;
- Providing support to assist employees with a safe return to work following an illness or injury.
- Recognising that health, safety and environmental performance contributes to overall organisational and business support.

5.3 Stakeholder Interests

Stakeholder interests must be considered and accounted for in asset management policy and strategy. The wide and varied views of the many stakeholders interested in ensuring that the network continues to provide a safe, reliable and cost-effective electricity supply to all customers and communities have been considered.

Key stakeholders and their principal interests are summarised below:

Table 11: Stakeholder interests

Key stakeholder	Main interests	Engagement
Customers	Public safety; service quality and reliability; price; new connections; communication	Social media, direct contact, annual service level survey, outage notifications, enquiries
Communities, Iwi, Landowners	Kaitiakitanga, mana whenua, land access and use; consultation; communication	Social media, direct contact
Regional and District Councils	Environmental performance and compliance;	Direct contact, engagement when projects align, monthly relationship meetings
Employees and Contractors	Safe and productive work environment; fair remuneration; training and development	Direct contact, staff surveys, meetings
Eastland Community Trust	Governance; financial performance; risk management	Direct contact, meetings (senior management EGL)
Commerce Commission	Default price path compliance; information disclosure; exercising good industry practice in asset management; risk management	Regulatory meetings and compliance reporting
The Electricity Authority	Pricing methodology; distributed generator connection and pricing; market operation and access	Direct contact
Work-safe	Workplace safety; electrical compliance and notifications	Reports and direct contact

Key stakeholder	Main interests	Engagement
Electricity retailers	Pricing methodology, billing, customer service; use of systems agreements;	Annual relationship meetings, shutdown notifications.
Distributed generators	Access to the network; connection agreements, price, operations management	Engagement through network approved contractors, meetings with owners of larger installations
Transpower	Load forecasting; GXP planning, technical performance; technical compliance	Indirect/direct meetings, relationship meetings for outages and performance issues, coordination of operational / maintenance issues

Where interests of different stakeholders do not align, or conflicts of interest exist, decisions are aligned with asset management policies. Where conflict may impact strategy and performance, these are elevated to an executive and Board level for resolution.

5.4 Stakeholder Engagement

Firstlight recognises the importance of engaging with businesses and consumers as key stakeholders of Firstlight's core services. Customers rely on safe and reliable delivery of electricity to maintain their productivity and household needs.

The objective is to engage with all stakeholders on the following topics:

- Customer views and preferences for their energy supply and their confidence in the electricity networks;
- Major investments and options that could impact communities and land owners;
- Pricing strategies and pricing decisions.

Firstlight engages with stakeholders to ensure that the needs of all customers are met, and their views are considered in shaping strategies and major investment decisions.

Multiple avenues are utilised to increase the public awareness of services and to understand the needs by:

- Surveying customers on their expectations and preferences for services;
- Hosting functions where stakeholders can engage with Firstlight;
- Using social media to communicate key initiatives and issues, including reviewing feedback posted on social media;
- Providing a 24/7 communication centre where faults and public safety concerns can be raised;
- Attending local functions (such as A&P shows) to enhance customer experience and interactions;
- Informing the public of planned and unplanned shutdown times, areas, and expected restoration times;
- Regularly communicating with landowners who are affected by Firstlight assets;
- Sponsoring local talent and fostering tertiary education.

The annual customer survey topics are based on the "line function service" attributes such as reliability, pricing, demand management, flicker and responsiveness to faults. The survey sample includes major consumers and a cross-section of other consumers in the Gisborne and Wairoa regions.

The results of consumer engagements are presented in Section 6.3.

6. Performance Review

This section evaluates the network's operational performance to determine if any systemic issues need to be resolved

6.1 Introduction

This section evaluates how the network has performed against the service level targets. The performance targets were updated in the 2020 AMP and are consistent with the standard set for the industry.

A full description of the service levels and targets is provided in Section 8.

This section reviews our performance against the operational service levels only. Additional "work on the business" targets are included in the Roadmap section, and an evaluation of performance against those targets is covered in that section.

Given the delay in releasing this plan, we have included RY2023 performance to cover ex-tropical cyclone Hale and cyclone Gabrielle (discussed in this section). These events were significant, and we have changed our asset management strategy as a result.

6.2 Safety

The overarching safety target is to have no serious harm to anybody working for, or on, Firstlight's network, or from any equipment owned or operated carrying out that work.

Table 12: Safety performance[33]

Safety performance	2016	2017	2018	2019	2020	2021	2022	2023
Harm to employees resulting in lost time[34]	2	-	-	1	1	1	1	1
Harm to contractors resulting in lost time	nm[35]	nm	nm	nm	nm	-	2	-
Serious harm to any member of the public	-	-	-	-	-	-	-	-
Serious damage to company property and equipment	nm	nm	nm	nm	nm	12	8	7
Serious damage to public property	1	-	-	1	3	-	-	2

Before the acquisition, Eastland Network increased its auditing program to enhance safety awareness and introduced various wellness initiatives to improve awareness and support for health-related issues. These safety and health-related initiatives are now delivered through Firstgas' processes and programs.

From a personnel and contractor safety perspective, no systemic issues require addressing within this AMP.

From a public safety perspective, the performance does not indicate any systemic issues. The asset fleet plans (Section 11) comment on asset-related safety issues and include plans to resolve any current or emerging asset safety issues.

[33] Note: This is only for incidents which occurred as a direct result of network operations or assets.
[34] Only includes our internal fault contractors, not external.
[35] nm = not measured.

Following our review, two minor recommended improvements were noted. These are related to improvements in recording public safety and contractor incidents to enable better analysis and prevention.

6.3 Customer Service

6.3.1 Results from the customer survey

During November and December 2022, Firstlight undertook its annual customer survey. The survey was taken before ex-tropical cyclone Hale and cyclone Gabrielle.

The survey involved 25 industrial customers and around 600 mass-market customers across the Gisborne and Wairoa regions.

In summary, customers:

- Agree that *keeping the power on*, *restoring power quickly when an outage occurs*, and *keeping prices low* is what is important to them;
- Ranked reliability as more important than maintaining low prices;
- Considered that we were doing an average to excellent job at maintaining reliability;
- Considered we were doing an average job at keeping prices low (however, there was a wide range of responses);
- Had a low awareness of TOU prices and industrial customers would generally find it difficult to shift load, with mass-market customers generally indicating that this would be easier for them;
- Had a low interest in pursuing electrification of process and home heating, installing solar PVs, buying electric cars or installing batteries. The exception was that industrial customers were considering electrifying their vehicle fleet.

The survey indicated that we are performing well concerning reliability but less so in relation to pricing and communication (refer to Table 13).

Table 13: Summary of customer survey performance

Areas	Target	Rating	Target achieved
Reliability (keeping the power on)	>80%	89% rated this good to excellent across Industrial and mass market	Yes
Reliability (response when an outage occurs)	>80%	88% rated this good to excellent across mass market and industrial sectors	Yes
Keeping prices low	>80%	50% rated this good to excellent across mass market and industrial sectors.	No
Communication (mass-market)	>80%	55% rated this as good to excellent[36]	No
Understanding of TOU pricing	n/a	Low	n/a
Ability to shift demand	n/a	Low	n/a
Intention to install rooftop solar	n/a	Low	n/a
Intention to purchase an EV	n/a	Low for mass-market customers High for industrial customers	n/a

36 These questions related to answering the phone, advice on planned outages, and advice on technical matters.

Areas	Target	Rating	Target achieved
Intention to purchase batteries	n/a	Low	n/a

6.3.2 How we are responding

Managing the price-quality trade-off

We discuss how we are responding to the price-quality trade-off in our discussion in relation to the energy trilemma balance (refer to Section 4).

Managing our reliability challenges

As shown in Sections 4.8 and 6.4, managing the reliability of the network has been challenging. Climate change is increasing the occurrence of adverse weather events, which is increasing outages on the network. In response, we have reviewed our asset management strategy with a strong focus on resilience and vegetation management (refer to Section 7 and 11).

Implementing cost-reflective pricing to support our region's transition to a net zero-carbon economy

Highly variable pricing structures are no longer relevant for the changing future of the industry. Consequently, cost-reflective/service-based pricing can more appropriately signal the network's costs. This step is critical for ensuring prices remain equitable across all consumer classes and minimising the risk of customers making uneconomic investments to bypass variable network prices.

Firstlight's strategy is to "Implement cost-reflective pricing to support our region's transition to a net zero-carbon economy." Implementing our pricing strategy seeks to balance cost reflectivity with other factors, such as the socio-economic situation in Te Tairawhiti and Wairoa and the varying quality of service across our network. Our pricing strategy intends to support the electrification of transport, the development of energy storage and DERs, and the electrification of industrial processes.

We introduced a new TOU pricing structure at the start of RY2021. TOU prices are now mandatory for all mass market and commercial customers with consistently communicating smart meters. TOU tariffs introduce higher prices during peak times of the day when the network is more congested and lower rates during off-peak times when there is plenty of capacity on the network. This indicates to consumers that consuming electricity off-peak may reduce or delay investments into network assets and shares this benefit with consumers who consume off-peak. The Electricity Authority has evaluated this approach in its recent scorecard assessment of distributor pricing and Firstlight has compared well against its peers.

During RY2023 (for prices commencing at the start of RY2024), we increased the fixed charge for our low-user domestic customers from 30c to 45c from 1 April 2023 (consistent with changes to Low User Fixed Charge regulations). We also introduced an asset cost allocator to our cost of supply model, which will better align prices with costs across our customer classes.

Responding to the energy transformation

To support New Zealand's net-zero goal, there is an expectation that consumers will change how they use electricity by embracing new technologies (such as EVs, solar PV and batteries) as the cost of these technologies reduces. Our customer survey results suggest that this change will be relatively slow in our region, but could happen quickly.

Notwithstanding the low appetite by consumers to substantially change how they use electricity, we have included additional demand and consumption growth in our most recent demand forecasts and have developed a strategy to guide our response to the changing energy environment (refer to Section 4 and 10). The additional growth and the pace of our response are consistent with the recent survey results, and we will closely monitor electrification trends in other parts of the country that will probably see changes sooner.

6.4 Network Reliability

6.4.1 The significant impact of adverse weather and vegetation in RY2023 (including the impact of ex-tropical cyclone Hale and cyclone Gabrielle)

Firstlight exceeded its regulated reliability (quality) cap in RY2023. As the DPP determination requires, Firstlight has provided the Commerce Commission with an unplanned interruption report[37]. This report is available on the Firstlight website.

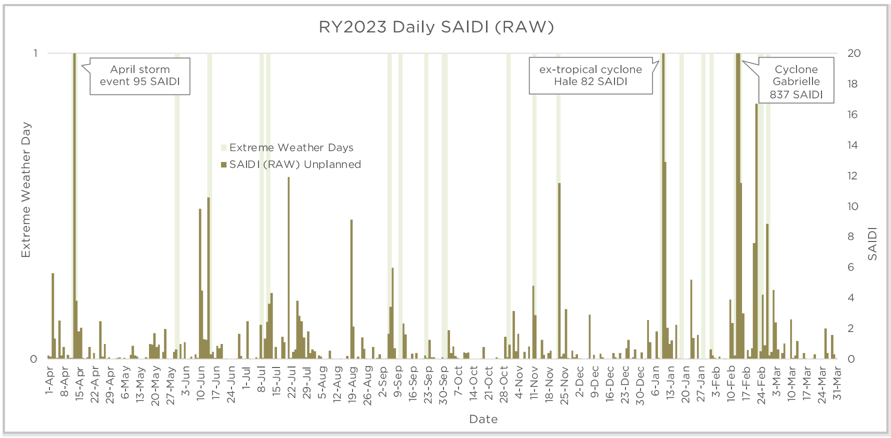
During RY2023, we experienced 44 days of extreme weather (MetService red and orange events), up from an average of 25 per year for the prior three years. Rainfall increased materially during RY2023 and was 50% higher than the average of the preceding three years.

The RY2023 extreme weather events comprised:

- The storm events of April, May, June, July, September and November 2022 (refer to Figure 47 and Figure 48);
- The floods and high winds experienced by ex-cyclone Hale on 11 January 2023 (refer to Figure 49);
- cyclone Gabrielle hit New Zealand from 12 to 14 February, with a national state of emergency declared on 14 February (refer to Figure 50 and Figure 51).

There was a strong correlation between SAIDI and extreme weather days (refer to Figure 45). The impact of the extreme weather was most apparent concerning the adverse environment, adverse weather and vegetation outages (refer to Figure 46). The adverse environment, adverse weather and vegetation that occurred on extreme weather days accounted for 1,191 SAIDI or 81% of the total SAIDI for RY2023.

Figure 45: RY2023 Daily SAIDI (RAW)



[37] Link to Report: https://www.firstlightnetwork.co.nz/tell-me-about/firstlight-network/regulatory-information/

Figure 46: The impact of extreme weather on outages

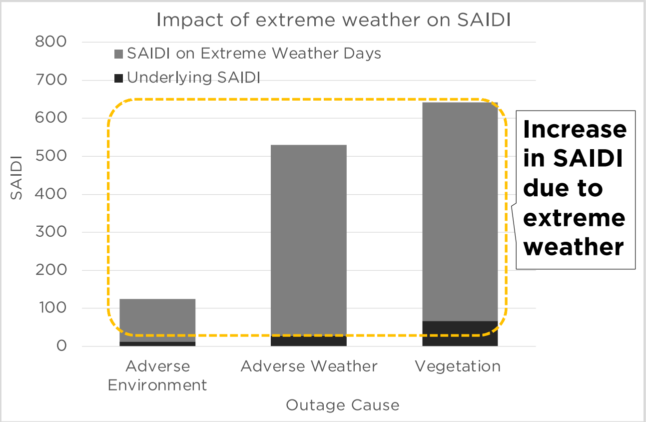


Figure 47: Line damage caused by trees outside the fall zone going through lines in April 2022

Figure 48: Line damage caused by forestry trees outside the fall zone in June 2022

Figure 49: Damage to infrastructure in Tairāwhiti caused by floods in January 2022

Figure 50: Main street of Wairoa township

Figure 51: Roading impacted in Tairawhiti

6.4.2 The impact of cyclone Gabrielle and our risk reduction, readiness, response and recovery

Cyclone Gabrielle hit the Hawkes Bay Region on 12 February 2023. Considered the costliest tropical cyclone on record in the Southern Hemisphere, the total damages from cyclone Gabrielle are estimated to be at least NZ$13.5 billion. Gabrielle was also the deadliest cyclone and weather event felt in New Zealand since Cyclone Giselle in 1968. Flood waters breached stopbanks across Hawke's Bay (which includes Wairoa township), caused partly by the buildup of forestry slash at bridges.[38]

Power was lost to all customers when the transmission network was damaged (refer to Figure 52). Most of the network performed very well. However, the infrastructure was severely damaged in some areas, and our network was no exception. Distribution network outages impacted 4,500 ICPs at the peak of the event. Due to the damage to roading and our network, it took us more than two weeks to restore supply to a few isolated customers following the cyclone events (refer to Figure 53).

During cyclone Gabrielle, high winds were the most significant cause of asset damage to overhead lines (the adverse weather outages in Figure 53). This accounted for 48% of the customers off at the cyclone's peak. The windspeeds experienced during cyclone Gabrielle were very close to current line design limits, and the windspeeds in some locations were likely above the design limits for older (pre-2000) poles.

Figure 52: Total customers-off during cyclone Gabrielle

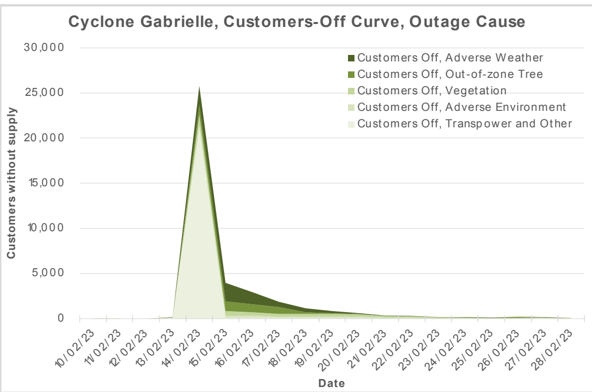
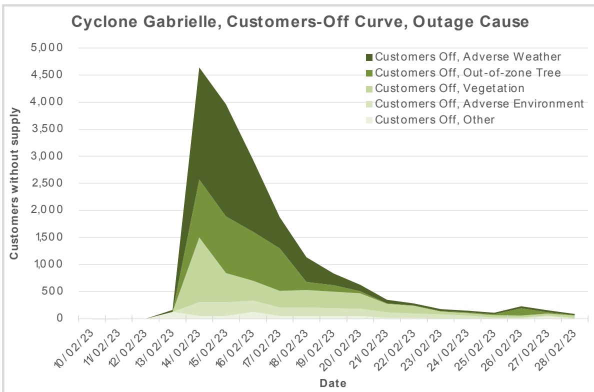


Figure 53: Distribution customers-off during cyclone Gabrielle



Vegetation outages were predominantly caused by trees outside the growth limit (refer to Figure 53). This accounted for 23% of the customers off at the cyclone's peak. Out-of-zone tree outages are further discussed in Section 11.

[38] Bidwell, Hamish (28 February 2023). "Cyclone Gabrielle: One-in-500-year flood prevention system on its way". The New Zealand Herald.

Our risk reduction, readiness, response, and recovery actions were reviewed as part of the distribution section review of cyclone Gabrielle.[39] We have extracted (below) relevant findings from the report that apply to Firstlight. These are being considered in our revised resilience strategy:

- Regarding risk reduction, our work is at an earlier stage concerning flooding, geotechnical hazards, and assessing how hazards may alter with climate change. These issues have emerged recently due to recent weather trends. We are still forming mitigation plans for flooding and geotechnical hazards;
- Much of our overhead network was installed before 2000, and design standards (pre-2000) were to a lower standard and less rigorously applied (reflecting the practices of the time). Hence, we have assets designed to older standards that are more vulnerable to high wind speed. As mentioned in Energia's report, the windspeeds experienced in some locations during Cyclone Gabrielle were highly likely to have been above the design limits for pre-2000 overhead lines;
- Regarding preparedness, we have appropriate emergency management plans to respond to weather events. We took the weather watches and warnings seriously and prepared accordingly. This included dispatching resources and equipment on the East Coast to respond more quickly;
- Regarding our response and recovery, we expanded the number of people involved in the response. However, due to the scale of the event, we did experience some constraints. The extent of the impact across New Zealand and the failure of the roading network prevented additional external resources from assisting in the early period of the event;
- It was difficult to assess the actual damage to the network due to the duration of the cyclonic conditions (which prevented aerial surveys), local helicopters being prioritised for life-saving work, and the inability of CDEM to advise on the state of the roading network to able us to dispatch field staff efficiently;
- The failure of the public telecommunication networks in our region impacted communication with customers and stakeholders. The failure prevented the public from being able to report lines down and other electrical hazards. However, our SCADA communication and communication with field staff is independent of the public system and operated throughout the event.

Overall, Energia considered that EDB responses to Cyclone Gabrielle were appropriate:

> 'Our overall comment is that EDBs did an appropriate job restoring supply and competently responded to a wide range of issues. We believe there are incremental improvements that can be made that will enhance restoration and improvement communication with customers.'

We are comfortable with this conclusion and are looking for incremental improvement as part of our resilience strategy. The resilience strategy will also address the design standard for pre-2000 lines (in critical areas), assess flooding and geotechnical hazards and prepare mitigation plans where appropriate.

6.4.3 Overall network reliability (long-term performance trend)

Unplanned SAIDI and SAIFI have been volatile since 2013 due mainly to the impact of extreme weather events on adverse environment, adverse weather, and vegetation outages. The SAIDI from other causes has been trending upwards (getting worse) in recent years due to the spillover effects of the extreme weather events on other outage causes (refer to Figure 54 and Figure 55).

[39] Energia "Report to Electricity Networks Aotearoa, Electricity Distribution Sector Cyclone Gabrielle Review", July 2023.

Figure 54: RAW SAIDI long-term trend

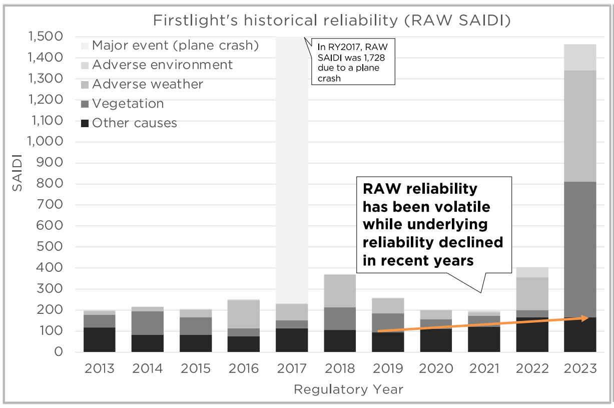
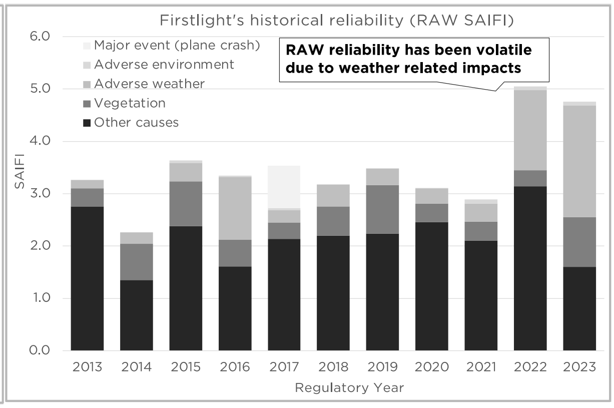


Figure 55: RAW SAIFI long-term trend



Firstlight is regulated under the DPP regime, including a "cap" on unplanned SAIDI and SAIFI.[40] Under the regulatory regime, major events are normalised to reveal an underlying trend in reliability. This process is referred to as "normalisation". From RY2021, the cap was reduced for unplanned SAIDI and increased for unplanned SAIFI.

Over the past four years, we have exceeded our unplanned SAIDI cap once. Due to the number and impact of extreme weather events in RY2023, we breached our regulatory SAIDI cap that year (refer to Figure 56). Our goal is to achieve our internal target in normal years; unfortunately we have exceeded our internal SAIDI target in all of the past four years due to the influence of adverse weather, adverse environment, vegetation and third-party damage. These are discussed later on in this section.

Over the past four years, we achieve our unplanned SAIFI target (refer to Figure 57).

Normalised unplanned SAIDI has been increasing in recent years due to the impacts of extreme weather events (refer to Figure 58). The impact of extreme weather events has not been as material on SAIFI (refer to Figure 59). Not all extreme weather events are adjusted through the normalisation process, which has contributed to the decline in "headroom" to the regulatory cap for SAIDI (refer to Figure 60 and Figure 61 concerning RY2023).

Figure 56: Normalised SAIDI vs. Target

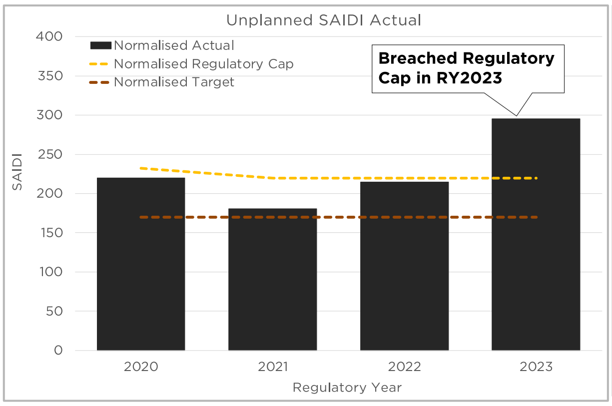
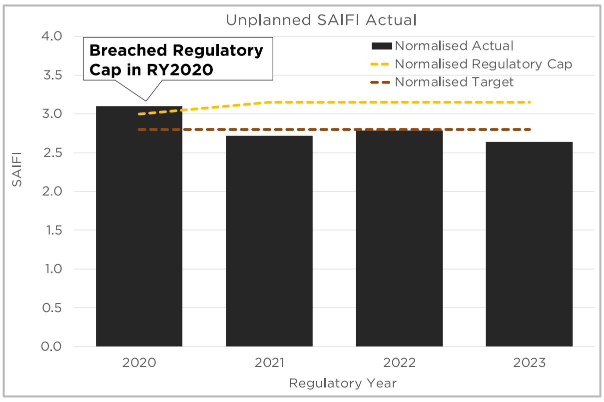


Figure 57: Normalised SAIFI vs. Target



40 The unplanned outage cap only came into effect from RY2021. Before RY2021, the cap included both planned and unplanned outages. We have recalculated an unplanned cap for periods before RY2021 to provide a useful time series.

Figure 58: Normalised SAIDI long-term trend

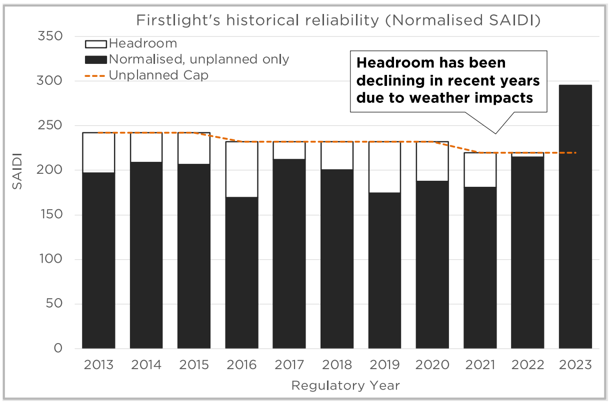


Figure 59: Normalised SAIFI long-term trend

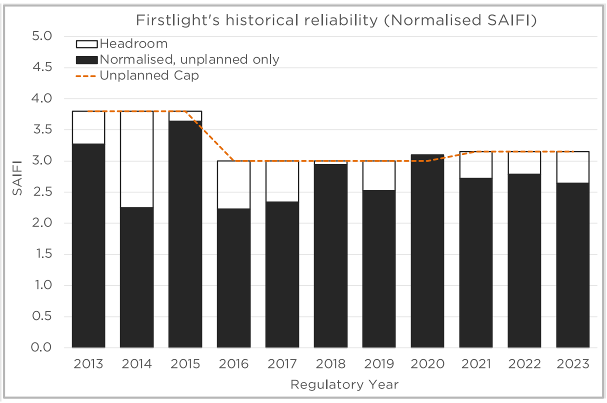


Figure 60: RY2023 Extreme Weather Days vs. Major Event Normalisation

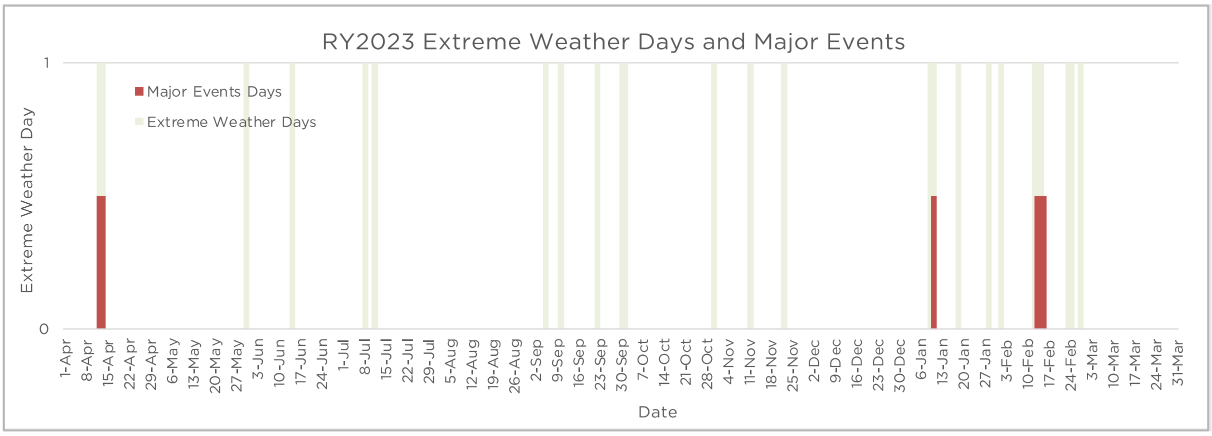
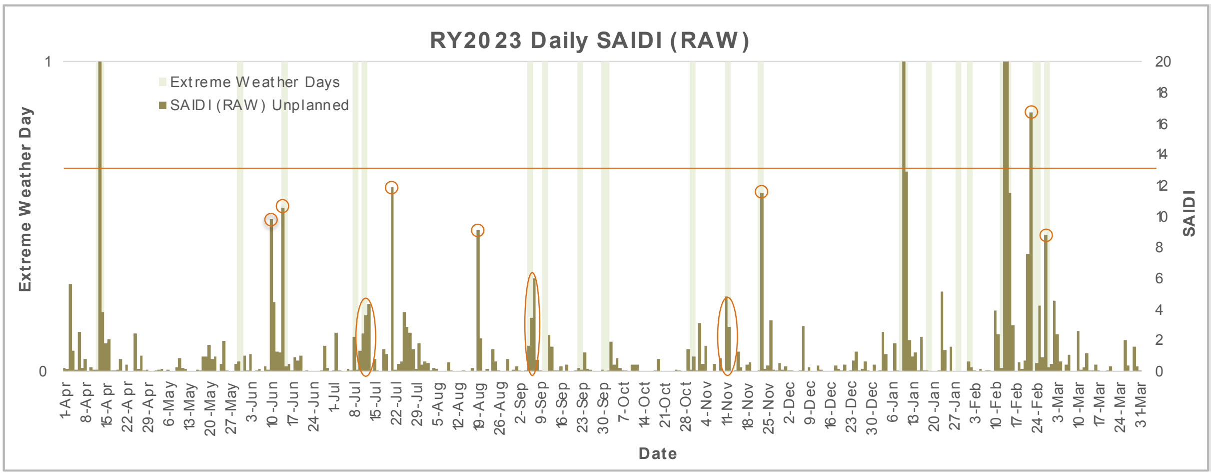


Figure 61: RY2023 Extreme Weather Days vs. RAW SAIDI



In the following sections, we look deeper at the key causes of unreliability. We also analyse the key causes of defective equipment and third-party damage.

6.4.4 Increasing incidents of extreme weather events

As mentioned in Section 4.8, The East Coast and Wairoa regions are increasingly being impacted by extreme weather. The number of extreme weather (MetService red and orange events) has increased yearly since RY2020. In RY2023, there were 44 extreme weather days, up 214% from RY2020. The increasing incidents of extreme weather events are the primary driver of unreliability on the network.

6.4.5 Adverse weather and adverse environment outages

Adverse weather and adverse environment SAIDI has increased materially since RY2020. In the RY2022 and RY2023 (periods when the incident of extreme weather was high), 85% and 95% of the SAIDI occurred during an extreme weather event (refer to Figure 62). As mentioned previously, the regulatory normalisation process is imperfect and most, but not all, adverse weather and adverse environment SAIDI was normalised (refer to Figure 63).

Figure 62: Adverse weather and adverse environment SAIDI on Extreme Weather Days

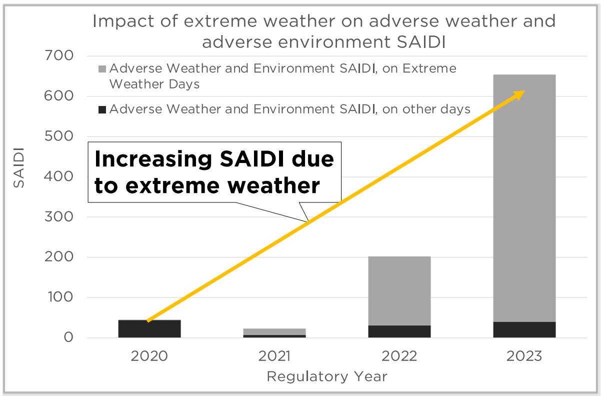
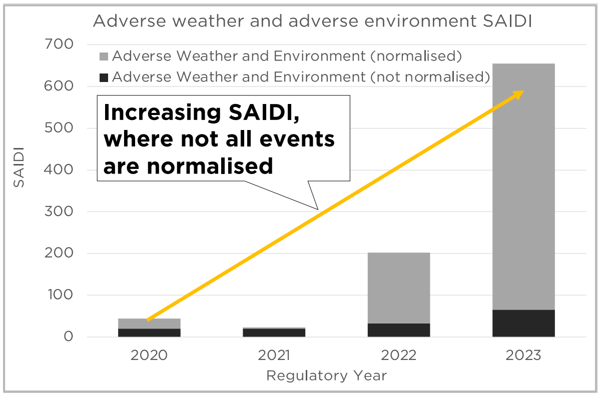


Figure 63: Normalisation of adverse weather and adverse environment SAIDI



The worst-performing feeders accounted for 85% of the adverse weather SAIDI[41] and 93% of the adverse environment SAIDI[42].

The six feeders most impacted by adverse weather and environment outages were:

- Ruatoria feeder: This was subject to multiple faults and trippings on the 50kV and 11kV lines during Cyclone Gabrielle. Diesel Gensets were used to supply the Ruatoria feeder; however, access to Ruatoria was limited, and we could not re-fuel the generator through the event. This meant we had to reduce the load on the generator and eventually stop supporting the load.
- Frasertown feeder: Cyclone Gabrielle was the major contributor to faults on the Frasertown feeder. The cyclone damaged the roading network, and we could not gain access to the fault for several days;
- Te Arai feeder: This was also impacted by access issues during Cyclone Gabrielle. There were multiple poles down on the feeder due to the cyclone. There were also several slips along Waingake Road, which the Te Arai feeder traverses, meaning restoration work was stalled until access was available;
- Matawai feeder: This was impacted by multiple storm events during the year. The most significant outages occurred during Cyclone Gabrielle. Access was an issue, with contractors unable to reach the fault until the following day;
- Mata feeder: This feeder traverses rugged terrain through forestry blocks and rural areas. During both ex-tropical cyclone Hale and Cyclone Gabrielle, landslips brought down sections of the line. During the weather events, access along Mata Road was limited. The majority of the customers were restored, but small pockets of customers were without power for over a week, resulting in the significant SAIDI contribution;
- Toko-tie feeder: A large landslip on State Highway 35 between Tokomaru Bay and Te Puia brought down multiple network spans that impacted the Toko-tie feeder. The slip also restricted access to the fault, and the silt from cyclone Gabrielle meant repair work was prolonged.

[41] These were the Ruatoria, Frasertown, Te Arai, Matawai, Mahia – Tahaenui, Tahora, Hicks Bay, Dalton, and Mahia feeders.
[42] These were the Mata, Toko-tie, Te Araroa, Inland, Tiniroto, Parikanapa, and Tikitiki feeders.

Minimising the impact of extreme weather and addressing vulnerabilities on these feeders is being addressed through the resilience strategy.

6.4.6 Vegetation outages

Vegetation SAIDI has increased materially since RY2020 due to the increase in extreme weather events. In the RY2023, 90% of vegetation SAIDI occurred during extreme weather (refer to Figure 65). As mentioned previously, the regulatory normalisation process is imperfect and most, but not all, vegetation SAIDI during an extreme weather event was normalised (refer to Figure 66).

In our 2021 AMP, we set targets for storm and underlying vegetation SAIDI. The targets included a 5% improvement each year. In RY2021 and RY2022, we met the target. However, in FY2023, due to the number of extreme weather events, we exceeded the target.

Figure 64: Vegetation SAIDI vs. Target

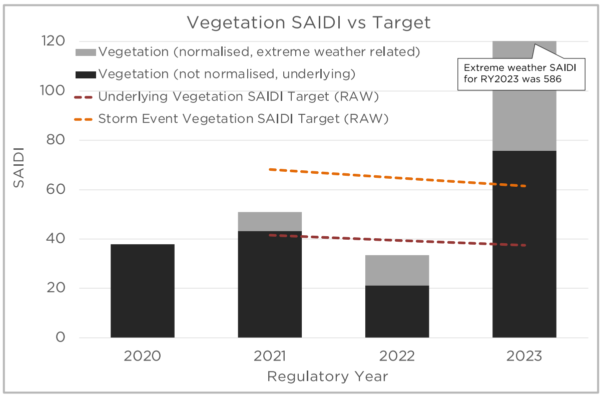


Figure 65: Vegetation SAIDI on Extreme Weather Days

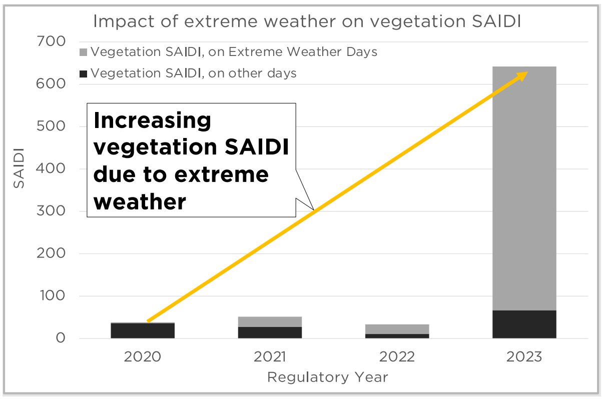
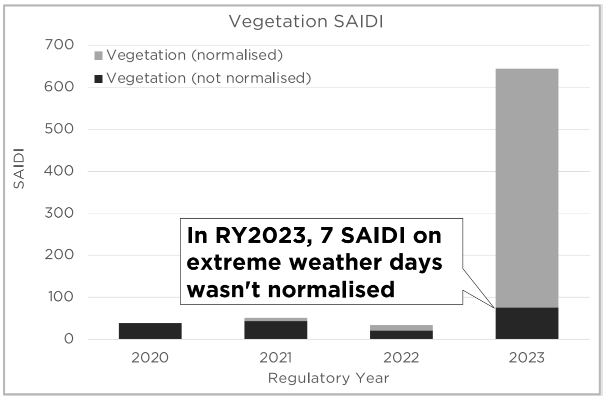


Figure 66: Normalisation of vegetation SAIDI



The principal cause of the increase in vegetation SAIDI is out-of-zone[43] tree contact (refer to Figure 67 and Figure 68). The out-of-zone tree contacts were mainly a result of extreme weather. However, not all were normalised for regulatory purposes. The impact of out-of-zone plantation trees was material in RY2023.

[43] Out-of-zone means trees (or branches) outside the growth limit zone as defined in the Electricity (Hazards from Tress) Regulations 2003. Refer to Section 11 for further details.

Figure 67: Out-of-zone vegetation SAIDI (RAW)

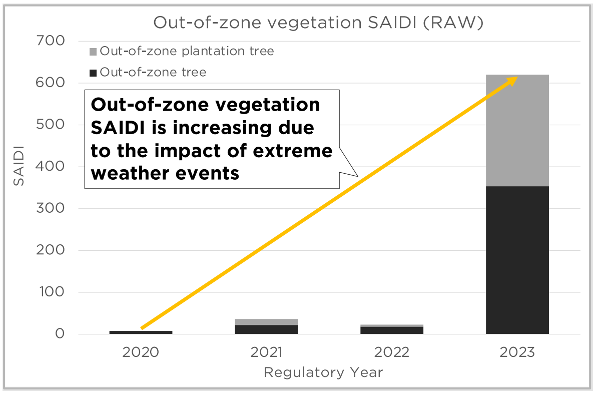
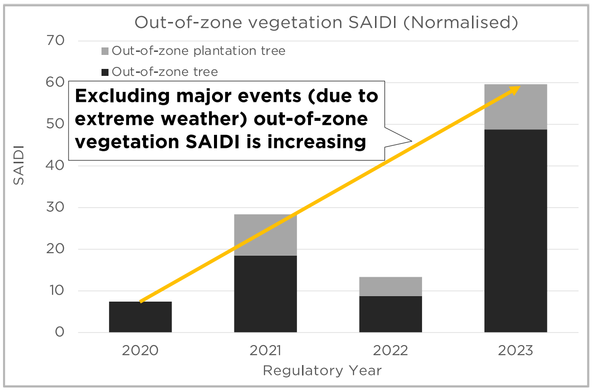


Figure 68: Out-of-zone vegetation SAIDI (normalised)



Outages caused by in-zone[44] vegetation contact have been improving, excluding the impact of major events caused by extreme weather events (refer to Figure 70). This reflects the positive outcomes of our vegetation management strategy introduced in RY2020 (discussed further in Section 11). The RAW vegetation SAIDI improved to RY2022 but declined in RY2023 (refer to Figure 69). The decline was due to the significant number of extreme weather events experienced during RY2023.

Figure 69: In-zone vegetation SAIDI (RAW)

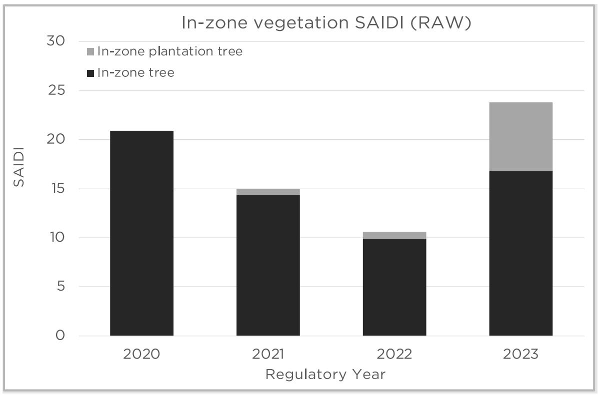


Figure 70: In-zone vegetation SAIDI (normalised)

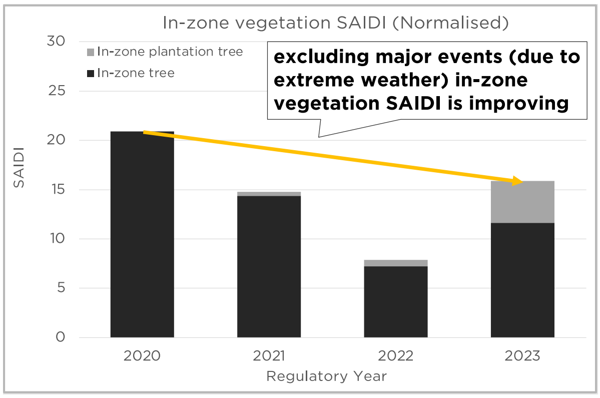


Table 14 shows the worst-performing feeders by vegetation SAIDI. These feeders contributed 78% of total vegetation SAIDI, and consistent with the preceding analysis, out-of-zone trees caused most of the outages.

The feeders marked with "*' in Table 14 were on the worst-performing feeder list from RY2021. Most of these feeders showed improvement in the in-zone vegetation performance, which reflects the improvement in vegetation clearance achieved on these feeders. We discuss the improvement in the worst-performing feeders in Section 6 and 11).

[44] In-zone means trees (or branches) within the growth limit zone as defined in the Electricity (Hazards from Tress) Regulations 2003. Refer to Section 11 for further details.

Table 14: Worst performing feeders for vegetation SAIDI

Feeder	In-zone tree SAIDI	Out-of-zone tree SAIDI	In-zone plantation tree SAIDI	Out-of-zone plantation tree SAIDI	Other SAIDI	Total SAIDI	% of Total SAIDI
Raupunga*	-	19.3	-	83.0	-	102.4	16%
Tauwhareparae	-	67.3	-	20.0	-	87.3	14%
Inland	-	68.0	2.9	0.6	-	71.4	11%
Kanakanaia	-	4.4	-	37.2	-	41.6	6%
Whatatutu*	-	2.5	3.8	33.7	-	40.0	6%
Tiniroto	-	3.5	0.1	34.3	-	38.0	6%
Ruatoria	0.4	35.1	-		-	35.6	6%
Waimata*	3.4	2.7	-	24.3	-	30.3	5%
Makarika	0.5	22.0	-	6.1	-	28.7	4%
Whangara	-	0.6	-	24.5	-	25.1	4%
Worst Performing	**4.4**	**225.5**	**6.8**	**263.6**	**-**	**500.2**	**78%**
Total Vegetation	**16.8**	**353.5**	**7.0**	**266.8**	**0.4**	**644.5**	

We continue to work on solutions to vegetation outages, which are discussed further in our vegetation strategy in Section 11.

6.4.7 Vehicle damage incidents

Vegetation SAIDI has steadily increased since RY2020 (refer to Figure 71). Concerning the high incidence of vehicle damage in RY2023, we suspect the increase in extreme weather events and the significantly higher rainfall contributed to the increase.

Feeders that have historically been impacted by vehicles have been identified (refer to Table 15). We plan to implement further risk mitigations (i.e. barriers or speedbumps), or we will consider relocation where practical. However, this work must be consulted with the local Council and Waka Kotahi. Progress has been slow to date.

Figure 71: Vehicle Damage SAIDI (RAW)

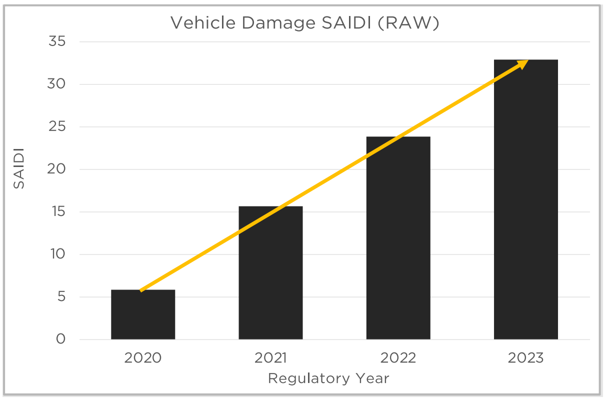


Table 15: Third-Party Interference Count

Feeder	2017	2018	2019	2020	2021	2022	2023	Feeder runs along State Highway
Hicks Bay	1			4	1	2		Yes
Tikitiki	2	1	1			1	1	Yes
Haisman	1		2					Yes
Lavenham		2		1	3	2	1	Yes
Waimata		5	1			1	6	Partly
Muriwai		2	4		2		3	Yes
Whatatutu	2		2		1		2	No
Matawai	1	2			3			Yes
Mahia	1	2			1	2		Yes

6.4.8 Defective equipment outages

We generally see an improvement in defective equipment SAIDI and outage numbers (refer to Figure 72 and Figure 73).

Figure 72: Defective equipment SAIDI

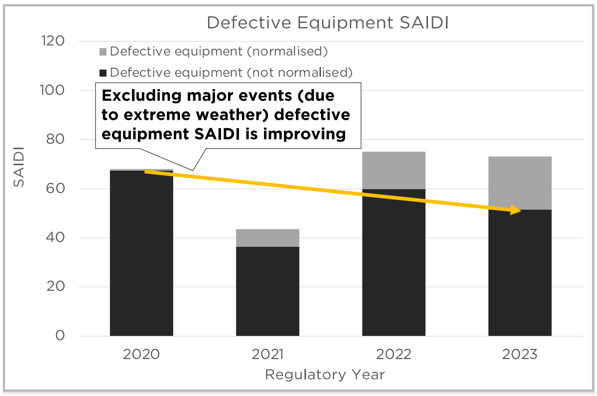
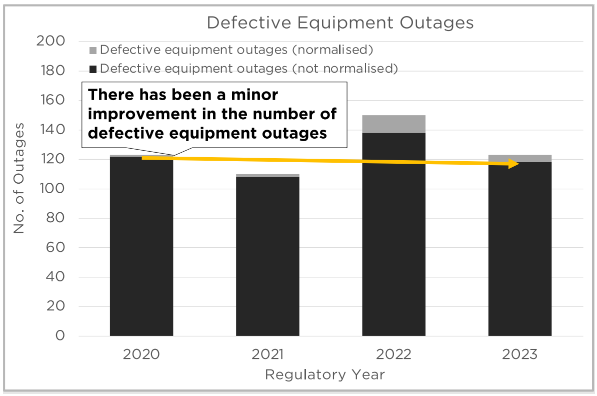


Figure 73: No. of defective equipment outages



The number of outages for underlying asset types has generally improved; where there has been some deterioration, this was weather-related (refer to Table 16 Table 17).[45]

The number of outages was reduced between RY2020 and RY2023 for most asset types, except for conductor–binding, cross-arms, insulators, pole-mount transformers, fuses, and cable terminations. As shown in Table 17 the increase in the number of outages for these asset types was primarily weather-related—that is, the increase in the number of outages occurred during Extreme Weather Days (that were not Major Events) or occurred on the spillover day (being the day after the Extreme Weather Day). It is generally recognised that the weather event most likely caused a defective equipment outage on the day following the weather event.

After accounting for Extreme Weather and spillover days, the deterioration in the number of outages is not considered material. There was a minor increase for cross-arms (4 more), insulators (2 more), and fuses (4 more). Given the material increase in extreme weather events and rainfall over the entire RY2023, it is probably unsurprising that we saw an increase in faults on crossarms, insulators and fuses.

[45] Equipment failures during extreme weasther should be categorised as adverse weather. However, sometimes this did not occur so we excluded defective equipment outages that occurred during Major Events. Defective equipment outages that ocurred during Exteme Weather Days (many of which were not Major Events) are included below, unless indicated otherwise.

Table 16: Defective Equipment by Asset Type[46]

Defective equipment type	2020	2021	2022	2023	Increase	% Change
Zone substation equipment	1	3	6		(1)	(100%)
Pole mounted switchgear		8	4	1	(7)	(88%)
ABS	13	3		2	(11)	(85%)
Softwood pole		3	3		(3)	(100%)
Hardwood pole	13	6	15	13	0	0%
Conductor - binding		3	3	5	2	67%
Conductor - joint (and jumper)	28	13	10	10	(18)	(64%)
Conductor - termination	2	10	9	2	0	0%
Conductor	18	17	30	18	0	0%
Crossarm	5	6	15	12	7	140%
Insulator	5	6	4	11	6	120%
Pole-mounted transformer	12	15	18	14	2	17%
Fuse	7	11	11	15	8	114%
Cable	10	2	6	9	(1)	(10%)
Cable - joint	1		1	1	0	0%
Cable - termination	4	1	6	5	1	25%
Ground-mounted transformer	1	3	4		(1)	(100%)
Defective equipment other			5	4	(1)	(20%)
Switchgear	1			1	0	0%
Other	2				(2)	(100%)
Total	**123**	**110**	**150**	**123**	**0**	**0%**

Table 17: Defective equipment type, excluding extreme weather and spillover

Defective Equipment Type	2023 Excluding Extreme Weather or Spillover	2020	Increase	% Change
Conductor - binding	3	3	0	0%
Crossarm	9	5	4	80%
Insulator	7	5	2	40%
Pole-mounted transformer	9	12	(3)	(25%)
Fuse	11	7	4	57%
Cable - termination	4	4	0	0%
Total	43	36	7	19%

46

6.4.9 Planned outages

Our planned SAIDI and SAIFI is slightly above our targets set in the 2021 AMP, but well below the cap (refer to Figure 74 and Figure 75). We are comfortable with how planned outages are tracking.

Figure 74: Planned SAIDI vs. Target

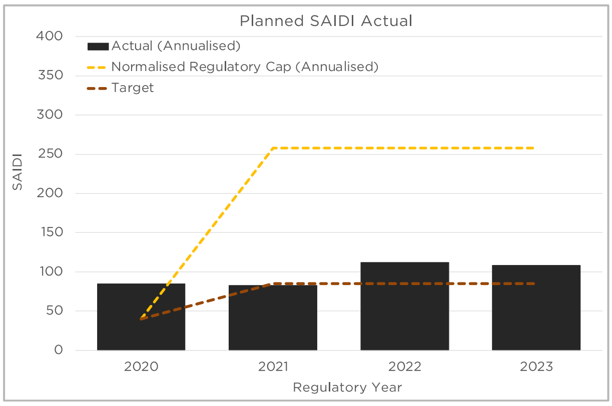
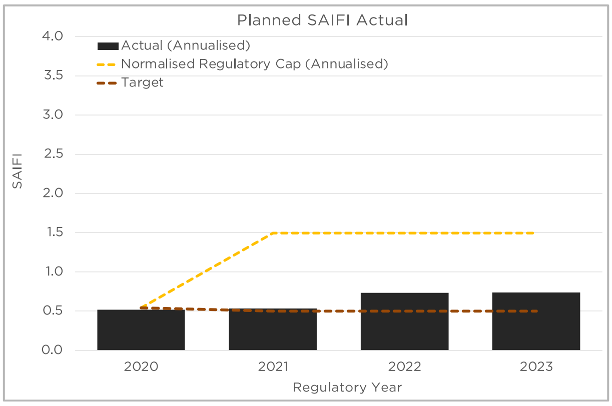


Figure 75: Planned SAIFI vs. Target



6.4.10 Fault restoration times

This will be included in the 2024 AMP.

6.4.11 Progress on the recommendations made in the 2021 AMP

We have made significant progress on the seven reliability improvement recommendations in the 2021 AMP. These have been reported in Appendix 4.

6.4.12 How we are responding

Analysis of faults has exposed several key weaknesses in the network, both operational and configurative.

Based on these issues, several recommendations have been identified that are included within the fleet plans, asset replacement plans, network development plans, and human resource allocations and are summarised in the table below.

Table 18: Network key Issues and recommendations

Issue	Recommendation	Potential improvement
We have seen a material increase in the impact of extreme weather on adverse weather and adverse environment outages. • We experienced significant damage during ex-tropical cyclone Hale and Cyclone Gabrielle, and a few customers were impacted for over two weeks. • The worst-performing feeders accounted for 85% of the adverse weather SAIDI[47] and 93% of the adverse environment SAIDI[48]. • We have assets designed to older standards (pre-2000) that are more vulnerable to high wind speed. • Diesel Gensets on the Ruatoria feeder could not re-fuel the generator due to road closures during Cyclone Gabrielle.	Enhance our resilience strategy, including: • Investigate the nature of the material outages on the worst-performing feeders to determine if there are improvement opportunities available; • Assess flooding and geotechnical hazards and prepare mitigation plans where appropriate. • Assess areas where there are pre-2000 lines in critical areas. Assess the risk and prepare mitigation plans where appropriate. Review our preparedness plans:	Not yet quantified. This is expected to reduce the adverse weather and adverse SAIDI.

[47] These were the Ruatoria, Frasertown, Te Arai, Matawai, Mahia – Tahaenui, Tahora, Hicks Bay, Dalton, and Mahia feeders.
[48] These were the Mata, Toko-tie, Te Araroa, Inland, Tiniroto, Parikanapa, and Tikitiki feeders.

Issue	Recommendation	Potential improvement
• Road closures impacted restoration time during ex-tropical cyclone Hale and Cyclone Gabrielle.	• Investigate contingency plans to address potential critical-route road closures (including. • Investigate opportunities to enhance mutual aid.	
Crossarm and insulator faults have increased	• Investigate the failures and condition of crossarms and determine if there are priority areas for crossarm renewal	Not yet quantified.
	• Assess whether different crossarm materials can better match the MPL for crossarms and poles.	Not yet quantified.
Increase in vehicle damage to the network	• Review our prior assessment to determine if new high-risk areas require mitigation.	Not yet quantified.
There was a material increase in vegetation outages in RY2023. These were principally caused by out-of-zone vegetation and out-of-zone plantation trees.	Update our vegetation management strategy and plan: • Review/progress the solutions for managing out-of-zone vegetation and plantation tree risk. • Review the worst performing feeders (Raupunga, Tauwhareparae, Inland, Kanakanaia, Whatatutu, Tiniroto, Ruatoria, Waimata, Makarika, Whangara) for vegetation risks and determine remediation opportunities.	Not yet quantified.

6.5 Asset Management, Utilisation and Efficiency

Measures concerning asset performance are included.

6.5.1 Underlying asset fault rate

The underlying fault rate measures the network's performance in areas where Eastland Network has a reasonable level of influence. It includes faults from defective equipment, adverse weather, and human error (and excludes lightning strikes and third-party interferences). The performance of the 11kV system was adversely impacted in RY2022 and RY2023 due to the extent of adverse weather and cause unknown events for those years.

Table 19: Underlying network fault rate performance

Underlying asset fault rate (faults per 100km)	Target	Actual 2022	Actual 2023	Comments on variance
110kV overhead lines	0.9	0.7	1.0	The RY2023 outage rate was due to Cyclone Gabrielle.
33/50kV overhead lines	3.64	1.5	2.7	Complied with target
11kV overhead lines	12.2	21.8	24.7	The RY2023 outage rate was due to ex-tropical Cyclone Hale and Cyclone Gabrielle

6.5.2 Defective equipment fault rate

Table 19 shows the underlying asset failure rate. Only cables, crossarms/insulators and ground mount switchgear were materially above target. This is our first measurement year, so it is too early to draw any significant conclusions. Asset fault trends are included in Section 6.4.8.

Table 20: Underlying asset fault rate performance

Faults per equipment type	Unit of measure	Target 2023 to 2025	Actual 2023	Comments
Zone substation equipment	Per 1k units/year	<7.5	0.0	-
Pole (wooden)	Per 10k units/year	<7.4	7.4	-
Pole (concrete)	Per 10k units/year	~0	0.0	-
Pole (crossarm or insulator)	Per 10k units/year	<3.6	6.0	Above target
Conductor (incl. jumpers and joints)	Per 100km/year	<1.6	1.2	-
Underground cable (incl. termination)	Per 100km/year	<7.7	10.7	Above target
Ground mount transformer	Per 1k units/year	<4.6	0.0	-
Pole mount transformer	Per 1k units/year	<5.0	4.6	-
Ground mount switchgear	Per 1k units/year	<0.9	2.7	Above target
Pole mount switchgear	Per 1k units/year	<4.3	4.8	Above target

6.5.3 Asset utilisation

Table 21: Asset utilisation measures

Asset utilisation measures	Target	Actual 2022	Actual 2023	Comments on variance
Asset per ICP	$6,472	6,951	7,747	The increase was mainly due to indexation due to higher CPI between RY2021, RY2022 and RY2023
Load factor	54%	55%	55%	The slight increase indicates an improved utilisation of existing assets. This is driven by higher demand.
Capacity utilisation	23%	24%	24%	As above

6.5.4 Losses

Whilst losses appear high, these targets are considered acceptable as a network with low losses is a potential sign of over-investment. Currently, there are no investments to reduce losses.

Table 22: Loss measure

Losses	Target	Actual 2022	Actual 2023	Comments on variance
Loss Ratio	9.5%	8.8%	8.3%	The power factor correction on the 110kV line and the promotion of power factor correction in the industry have contributed to the improvement in losses.

6.6 Delivery

6.6.1 Capturing condition information to support the new asset health assessments.

In RY2020, we introduced a new method of assessing asset health using the DNO Methodology and commenced capturing condition data to support the new methodology. We have made significant progress in completing the necessary asset inspections (refer to Table 23).

Table 23: Current percentage of asset condition data captured

Asset class	No. of assets in the fleet	No. inspected since 2020	% assets inspected since 2020	Target completion	Comments
Concrete poles	17,767	9,323	52.4%	2024	Expected 2025
Wood poles	17,340	8,956	51.6%	2024	Expected 2025
Distribution OH Open Wire Conductor	-	-	-	-	-
3.3/6.6/11/22kV Switches and fuses (pole mounted)	4,413	2,562	58.1%	2024	Expected 2025
Pole mounted transformers	3,056	1,708	55.9%	2024	Expected 2025
3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	44	34	77.3%	2024	Expected 2025
Zone substation Switchgear	148	87	58.7%	2021	Expected 2024
GM Transformers	564	539	95.5%	2023	Expected 2024
GM Switchgear	368	297	80.7%	2023	Expected 2024
Zone Sub Transformers	36	33	91.6%	2021	Expected 2024

Given the progress made, the data accuracy scores have improved for concrete poles[49], zone substation buildings, ground-mounted zone substation switchgear[50], and ground-mounted distribution switchgear.

6.6.2 Completion of planned capital work

Measuring financial and physical progress on planned work completion within the reporting periods provides useful data to monitor. The target is to achieve >95% completion for planned capital work.

Table 24: RY2022 Measures for the completion of planned work

Expenditure category	Target 2022 ($000)	Actual 2022 ($000)	Target >95%	Comments on variance
System growth (financial)	1,741	799	Not achieved	More than $700k of the underspend related to the Mahia 33kV line extension project (due to difficulties securing consent to land) and the Thermal Upgrade Project (which was impacted by supply chain challenges).
Asset replacement and renewal (financial)	7,324	7,495	Achieved	There were some over- and under-spends due to weather events and supply chain problems in increases in material costs. Some bigger overspends were seen on the most significant projects, e.g. Gisborne sub bus extension, T1

49 This improvement reflects our increasng confidence in the age and health data given the inspections completed.
50 This improvement was a combination of condition inspection, quality of age data, and knowledge of type issues.

Expenditure category	Target 2022 ($000)	Actual 2022 ($000)	Target >95%	Comments on variance
				5MVA Tologa replacement and 11kV pole replacements. Underspends were seen on the following projects: Replacement of T1 Patutahi 12MVA, conductor replacements in Wairoa and 50kV pole replacements.
Reliability, safety and environment (financial)	235	277	Achieved	Overspend mainly due to no forecast for diesel generators' maintenance due to ownership transfer from Eastland Generation to Eastland Network. This overspend was partially offset by lower spending on replacing galvanised meter boxes.

Table 25: RY2023 Measures for the completion of planned work

Expenditure category	Target 2023 ($000)	Actual 2023 ($000)	Target >95%	Comments on variance
System growth (financial)	2,091	2,690	Achieved	The Mahia extension project contributed $435k to the overspend due to the timing of the purchase and delivery of the 5MVA 33/11kV Tyree Transformer. The second Gisborne injection point project was overspent by $305k due to higher equipment costs.
Asset replacement and renewal (financial)	9,967	11,670	Achieved	Expenditure was significantly above forecast due to adverse weather, most notably Cyclones Hale and Gabrielle in January and February 2023. Unplanned pole and line replacements saw an overspend of $2.4m This was offset partially by underspending in planned works that had to be deferred due to the reactive work due to storms. The accelerated pole replacement program and 50kV pole replacement program were underspent by $697k and $336k, respectively.
Reliability, safety and environment (financial)	300	718	Achieved	Overspend resulted from no forecast for diesel generator refurbishments and the purchase of an additional 80kVA Generator and trailer.

Note: Physical progress measures have not yet been implemented in time for this AMP.

6.6.3 How we are responding

We continue to experience consenting and land access issues for major line projects. Much of these delays are external to Firstlight. However, early commencement of consenting and land access procurement will assist in achieving the required timeline.

6.7 Financial Sustainability

Maintaining financial sustainability is essential for Firstlight Network to retain sufficient earnings to fund future capital works. The target WACC has dropped materially from 6.44% to 4.23% (post-tax nominal WACC) due to material reductions in the risk-free rate.

Due to the indexation of the RAB being recognised as regulatory income, the cash returns to the business have reduced with the reduction in regulatory WACC in DPP3. The low WACC will require a higher debt funding of capex, increasing the financial risk associated with the business.

Table 26: Measures for financial sustainability

Returns	Target[51]	Actual FY2022	Actual FY2023	Comments on variance
ROI (post-tax nominal WACC equivalent)	4.23%	9.41%	7.91%	The higher returns result from the higher than forecast CPI, resulting in higher than forecast indexation of RAB. The indexation of RAB is included in the assessment of financial returns.

[51] The WACC for the DPP3 regulatory period.

7. Asset Management Policy and Strategy

This section provides an overview of the objectives for managing Firstlight Network assets. The asset management policy and strategy are principles and objectives that respond to the issues raised in Sections 3

7.1 Overview

In this section, the revised asset management policy and strategy are outlined.

The asset management policy aims to set the principles to guide the direction and approach to managing the electricity network. Over the next year, we intend to review the policies and strategies to ensure they fully align with the context, our stakeholders and the objectives and strategy of Firstgas Group. We expect any changes will be evolutionary rather than material change.

7.2 Asset Management Policy

The existing policy asset management policy is...

Asset management policy
Firstlight Network is committed providing services that meet customers' needs, and supporting the growth and prosperity of the Tairāwhiti and Wairoa regions. Effective asset management is the foundation upon which we will meet this commitment, and at all levels of the organisation, we will work to: • Ensure the safety of the public, our staff, and contractors; • Develop, renew, and maintain our network in a way that meets the current and evolving needs of our customers; • Recognise the socio-economic diversity of our customers and deliver a cost-effective service; • Ensure that our asset management decisions are based on an evaluation of options that consider life cycle costs, benefits, and risks; • Report proactively and transparently on our investment plans, service performance, and risks, and consult with stakeholders where appropriate; • Implement effective asset management systems and processes, including the capture and retention of information on our assets; • Operate in an environmentally sustainable and ethical manner; • Meet all statutory and regulatory obligations; • Continually improve our asset management systems; • Develop our resources and capabilities, both internally and externally, to deliver our plans.

7.3 Asset Management Strategy

In light of the key issues facing the network and the direction established by the asset management policy, a strategy to shape asset management activities over the next decade was developed in our 2020 AMP.

Our asset management strategy sets the direction for managing our electricity network assets. It has been developed with attention to:

- Describing the key objectives and initiatives that will be pursued to achieve the asset management policy over time;
- Delivering a service that complies with regulated quality thresholds;
- Driving continuous improvement programs to ensure an efficient and effective network business is provided.

We have made two material changes to the asset management strategy in this AMP. The first change was to enhance the resilience initiative. This is now more wide-ranging in response to the impacts of climate change on extreme weather events. The second change is to bring in the energy trilemma as a key strategy in response to upward pressure on prices. We have included additional discussion on these initiatives in Sections 7.4 and 0.

We have also updated the language used in the other initiatives to reflect the changing environment and progress made over the past three years. These changes have not altered the objective of each initiative but have ensured they keep pace with the changing environment.

The asset management strategy consists of eight initiatives:

Initiative	Description	Responds to...
2. Improve network resilience	Improve the resilience of the network to adverse weather events through: • Assessing wind, flooding and geotechnical hazards and implementing mitigation plans where appropriate (consistent with climate change); • Assess the worst-performing feeders to determine if there are improvement opportunities available; • Assessing the risk posed by pre-2000 overhead lines and implementing mitigation plans where appropriate; • Enhancing our contingency plans and mutual aid plans; • Enhancing our SCADA and OMS; • Enhancing vegetation management activities concerning key feeders and the out-of-zone trees (see initiative #2); • Increasing distribution network automation and security enhancements, particularly the opportunities to enhance generation use (see initiative #3). This includes the installation of three new 750 kVAe generators over the next six years.	• The increasing impact of climate change on extreme weather events • The increase in SAIDI and SAIFI due to extreme weather events • Feedback from our response to ex-tropical cyclone Hale and cyclone Gabrielle
3. Enhance vegetation	Continuous improvement of Firstlight Network's vegetation management plan, which includes:	• The significant impact on SAIDI from out-of-zone vegetation and

Initiative	Description	Responds to...
management activities	• Enhance the inspection and remediation process to deliver whole-of-feeder improvement; • Intensive subtransmission and key feeder vegetation management; • Enhance forestry owner engagement to achieve acceptable plantation fall zone clearances and harvesting clearances; • Support the industry in advocating for widening the growth limit zone to deliver wider line corridors.	plantation trees during extreme weather • Vegetation outages remain a key cause of outages
4. Enhance asset fleet plans	Maintain asset fleet plans using the DNO common asset indices for key assets to manage ageing network assets effectively.	• Our subtransmission and distribution assets are aging • The increase in crossarm faults
5. Increase the level of security and automation on the network	Enhance the security of the network through: • Resolving any current or forecast security gaps; • Increasing distribution feeder security through additional feeder interconnections; • Increasing the use of network automation (sectionalisers and reclosers) to minimise the impact of outages; • Investigating opportunities for additional generator support for feeder and substation security.	
6. Ensure the network can support the energy transformation and decarbonisation of the region	An increase in solar PV penetration, batteries, and electric vehicles is forecast to impact the network over the long term. Given the low starting point and the modest growth rates (due to socio-economic constraints), we do not expect any material issues before the mid-2030s. However, over the next 2-3 years: • Update the demand forecasts to align the national and international trends; • Prepare an energy transformation roadmap to minimise network costs and ensure no constraints on customers' use of new technology.	• The increasing pace of the energy transformation • Customer purchasing intentions in respect of EVs, solar PVs and batteries • Demand growth from electrification of transport and electrification of process heat • Evolution of flexibility markets
7. Develop solutions to cater for demand	A base case network solution has been developed to increase network capacity into Gisborne.	• The emerging risk of capacity constraints into Gisborne

Initiative	Description	Responds to...
growth from new industrial load and electrification	The next stage is to develop alternative options to a network solution to provide capacity into Gisborne.	• Demand growth from new industrial load • Demand growth from electrification of transport and electrification of process heat
8. Improve asset management practices and asset information	Our overarching goal is to improve the asset management maturity assessment score from 2.3 (out of 4) to 3.0. We have revised the date to achieve this to 2025 to account for the recent cyclone events and the transition onto the Firstgas Group system. Our focus is to improve network performance on the back of better analysis, enhance the quality of the AMP, and develop a culture of continuous improvements. The change in ownership has required migrating the asset management system to Maximo. Our focus for RY2024 and RY2025 is to: • Progress on capturing condition information; • Complete the transition to Firstgas Group, ensuring policies and processes remain effective throughout the transition; • Improve the maturity of asset risk management; • Improve the documentation or our asset management process.	• Our subtransmission and distribution assets are aging • The need to enhance asset health information (noting the significant progress already made) • Leveraging the economic of scope benefits available from Firstgas Group
9. Balance the Energy Trilemma consistent with stakeholder expectations	Given the increasing investment priorities and the need to maintain affordability, it is important that we communicate how we are balancing the issues. Starting with this AMP, we intend to: • Adopt the energy trilemma framework to communicate how we are balancing affordability, security, and sustainability; • Build our understanding of how stakeholders see this balance through our annual survey; • Enhance our consultation on significant investments that will shift the balance; • Enhance our forecasting of affordability, security, and sustainability.	• We serve one of the lowest socio-economic regions • Customer feedback on the importance of reliability and low prices • The need to communicate how we intend to balance the energy trilemma

7.4 Network resilience initiative

The networks resilience strategy comprises three themes:

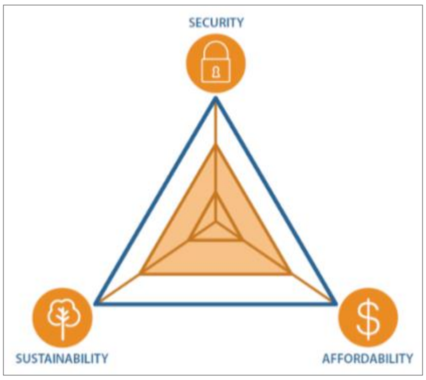
- Actions that reduce risk
- Actions to restore customers quickly
- Actions to address other weaknesses in out Resilience Management Maturity assessment.

Firstlight has put an initiative in place which will set out how the network will delivery on the strategy. This is not a one-off exercise but will form part of our overall ongoing asset management strategy. The initiative is explained in section 10.9.5.

7.5 Balancing the energy trilemma

Ensuring our services are affordable, investing to ensure our network is secure and resilient, and supporting New Zealand's decarbonisation efforts are material issues for Firstlight. The Energy Trilemma is a well-recognised framework (refer to Figure 44) for strategic optimisation in the energy sector. We have adopted this framework as it is well aligned with the choices and balance sought by the Government (and related agencies, like the Climate Change Commission and Electricity Authority). It is also a core part of the terms of reference for developing NZ's energy strategy.

Figure 76: The energy trilemma

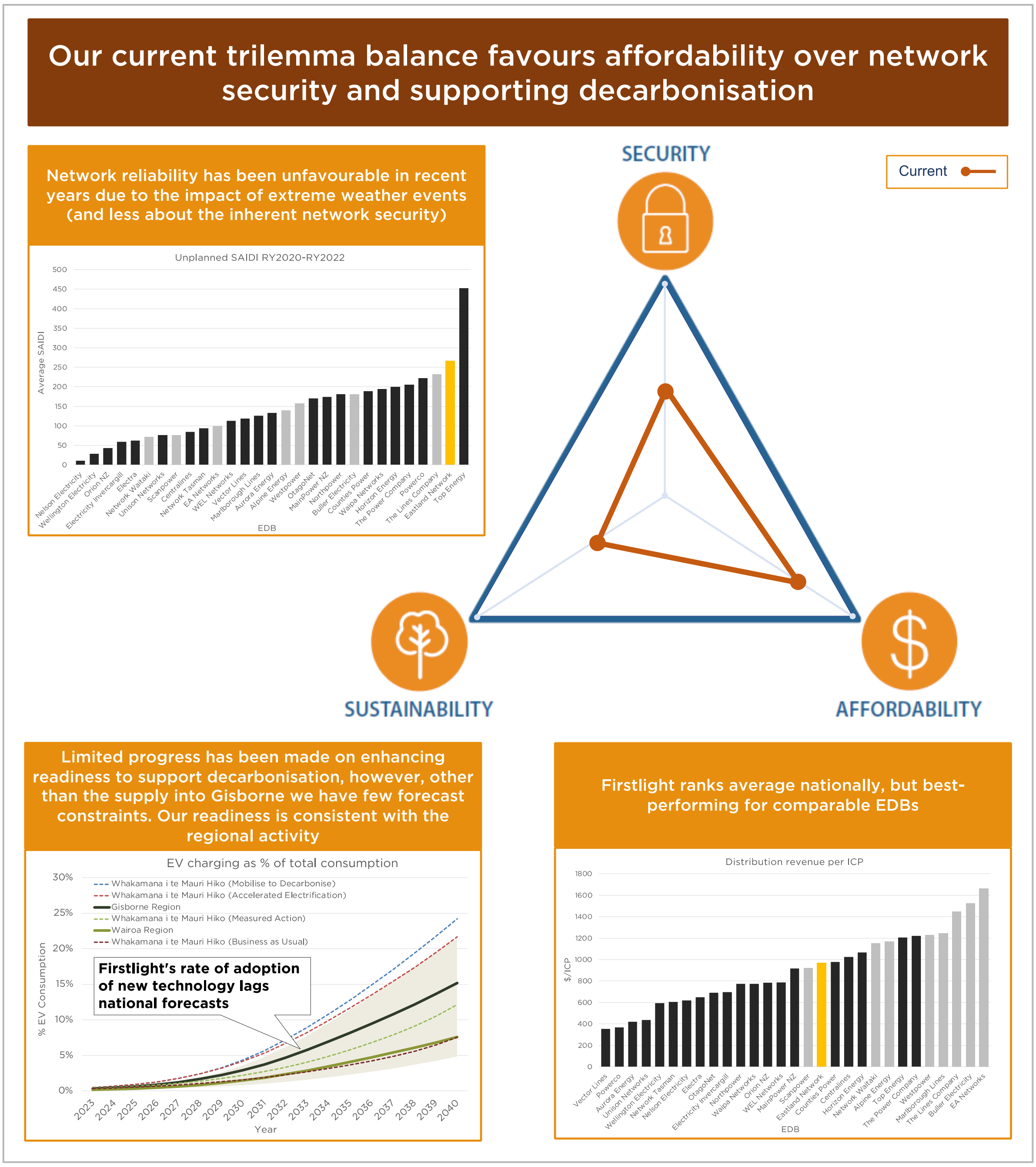


In the energy context, the three limbs refer to:

- **Security:** the ability to meet current and future energy demands reliably, including being resilience to external events;
- **Affordability:** the cost and access to energy (be this electricity via distribution lines or alternatives);
- **Sustainability:** supporting New Zealand's energy transformation, minimising emissions, and adapting to climate change.

Figure 77 shows our initial assessment against the energy trilemma framework. This indicates that we currently favour affordability over network security and supporting decarbonisation. The balance reflects our historical focus on minimising distribution prices to one of the lowest socio-economic regions of New Zealand (refer to Section 4.2). Our security assessment reflects the recent reliability outturn, which was materially impacted by adverse weather. And lastly, we are in the early stages of enhancing our readiness for the energy transformation. While at an early stage, our current position is not a constraint given the low electrification rate presently being seen across the network.

Figure 77: Our current energy trilemma balance



How this balance is forecast to evolve

The importance of the trilemma balance has increased for Firstlight due to the growing need for higher opex and capex to respond to our aging asset fleet, improve resilience, and support the electrification of transport and process heat.

Figure 78 shows our initial assessment of how the energy trilemma balance will evolve. This assessment indicates the direction of travel over the 10-year horizon of this AMP. The direction is shaped by:

- Improving reliability outcomes through an increase in investment in network resilience, security, automation, and vegetation management will reduce risk and enhance the ability of the network to withstand adverse events

- Improving our readiness to support the region's decarbonisation efforts. This involves investment in network augmentation (and alternatives) to deliver the necessary hosting capacity to support the growth in DERs and the increase in demand due to electrification.
- A decline in distribution affordability due to the abovementioned investments.

The key trade-off is that customers will see higher future distribution costs that will enable a network to support them as they transition parts of their energy usage from fossil fuels to electricity. Customers will also be connected to a more secure and resilient network that should respond and recover more quickly from climate-induced impacts.

We consider that it is appropriate to prioritise security and sustainability for three reasons:

- To maintain overall energy security for customers;
- To enable customers to reduce their total energy costs;
- To maintain consistency with the customer's priorities.

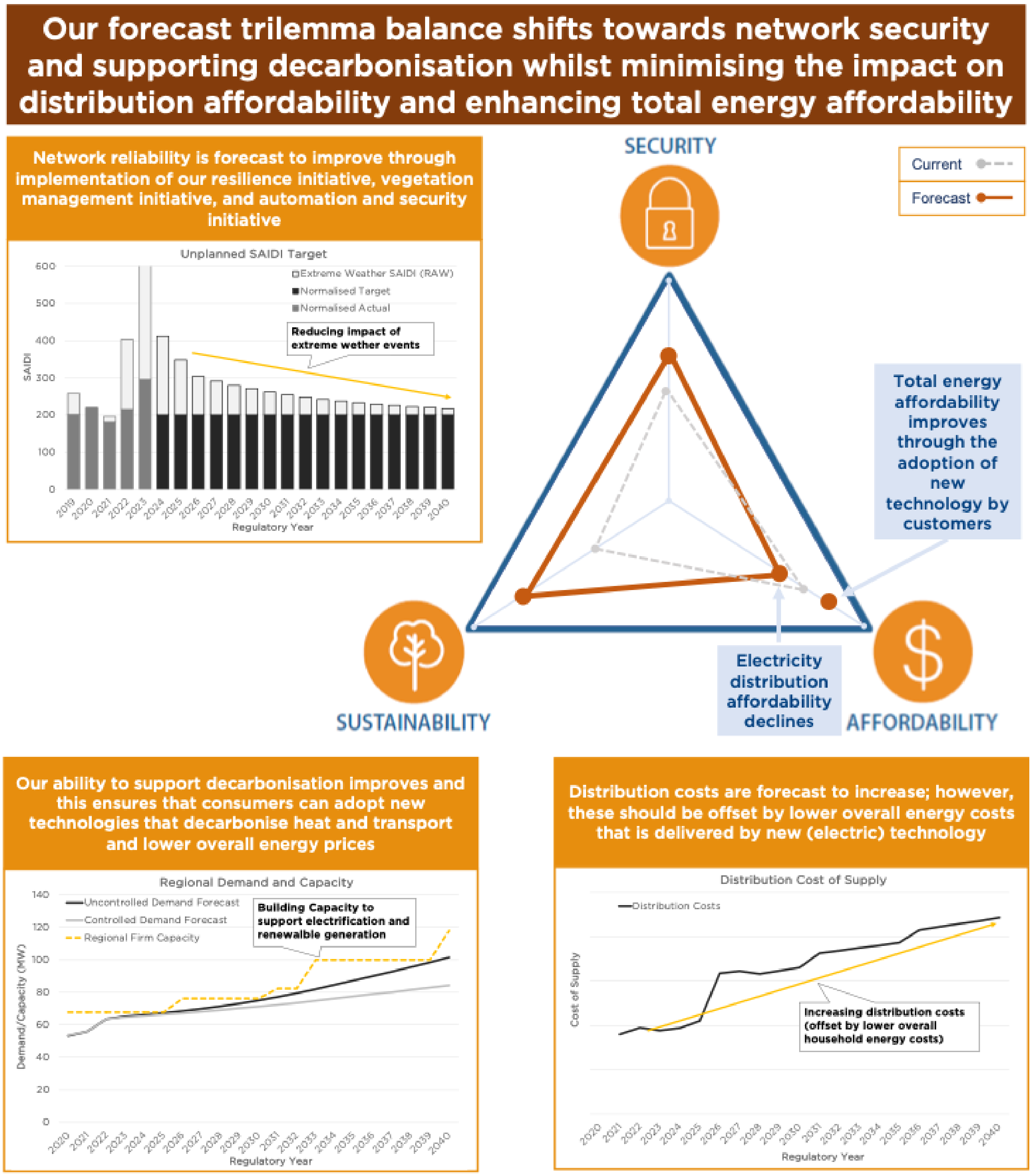
Regarding the first reason, given New Zealand's policy direction to decarbonise transport and heat using electricity, there will be greater reliance on electricity as an energy source—meaning there will be less energy diversity. This means Firstlight needs to ensure that its network is secure and resilient to enable its customers to prosper using electricity as their primary energy source (thereby offsetting the reduction in energy diversity).

Regarding the second reason, whilst electricity distribution costs will rise, pursuing the security and sustainability objectives should lead to reduced total energy costs for customers (as assessed by Sapare in their recent report for the Electricity Networks Association)[52]. For this to occur, customers need to invest in new technology, and given the high level of deprivation in our region, we believe that some of our customers will need to be supported in this transition. We will strongly make this point to the Government and relevant agencies.

Regarding the third reason, our customer survey feedback indicates that *keeping the power on*, *restoring power quickly when an outage occurs*, and *keeping prices low* are all important. However, customers generally ranked reliability as more important than maintaining low prices.

[52] https://www.ena.org.nz/news-and-events/news/total-household-energy-cost-to-reduce-over-time/

Figure 78: Our forecast energy trilemma balance



7.6 Increase in forecast expenditure.

We increased expenditure to support the asset management strategy in key areas. These include:

- Increasing the accelerated pole replacement program to address additional low-health poles in identified in recent inspections and in response to cyclone Gabrielle damage;
- Increasing vegetation management spend to enhance vegetation control on key feeders and on the worst performing feeders;
- Implementing a new SCADA and OMS to strengthen our responsiveness to faults and major events;
- Implementation of new generators to support the security of supply and the refurbishment of the existing generator fleet;

Refer to Section 14 for further details.

8. Service Levels

This section presents the service levels adopted to measure performance over the coming years. This will enable us to determine whether the asset management strategy is effective over the long term

8.1 Introduction

The service levels cover the following:

- Safety
- Customer service
- Network reliability
- Asset utilisation and efficiency
- Delivery
- Financial sustainability.

These measures encompass all areas of stakeholder interests and reflect the broad range of outcomes expected from good asset management.

Assessment of performance against these measures for the prior year is presented in Section 6.

8.2 Safety

Firstgas Group is committed to providing and maintaining a safe and healthy environment for all its employees, contractors, customers and the public. Firstlight Network shares this commitment.

Electricity businesses operate in high-risk areas, which pose risks to staff and contractors. The following safety targets have been established as a direct result of the policy and as a driver to improve health and safety performance. In saying that, Firstlight Network's target of zero harm is the only target that should be strived for, given the significance of the consequences should the target not be met.

Table 27: Firstlight Network safety targets

Performance measure	RY2024 to RY2028 Target
Harm to employees resulting in lost time	0
Harm to contractors resulting in lost time	0
Harm to any member of the public	0
Serious damage to company property and equipment	0
Serious damage to public property	0

[53] As a direct result of equipment owned or operated by Eastland Network

8.3 Customer Service

8.3.1 Customer Survey

Our consumers' experience ultimately measures how well we operate as a company in providing electricity to the region. Therefore, it is important to note our consumers' issues, performance levels, and expectations.

We conduct a customer survey each year containing qualitative and quantitative measures. The results help to inform our strategies and priorities, particularly how customers view the security and affordability limbs of the energy trilemma. The measures also provide us with a view of our customer service. Targets are only set for quantitative measurements and are shown below:

Table 28: Summary of customer survey targets

Areas	RY2024 to RY2028 Target
Reliability (keeping the lights on)	Greater than 80% of customers rate this as good to excellent
Reliability (response when outages occur)	Greater than 80% of customers rate this as good to excellent
Pricing	Greater than 80% of customers rate this as good to excellent
Communication	Greater than 80% of customers rate this as good to excellent[54]

8.4 Network Reliability

To support customer service reliability metrics, we also measure network reliability, including:

- Unplanned network reliability;
- Planned network reliability;
- Vegetation outage performance;
- Fault restoration time.

8.4.1 Unplanned network reliability targets

To measure network reliability, targets for the next five years are set against the following key measures:

- **SAIDI (System average interruption duration index)** measures how many system minutes of supply are interrupted for customers annually;
- **SAIFI (System average interruption frequency index)** measures how many customer interruptions occur annually.

These measures are consistent with industry-standard practice, information disclosure, and electricity distribution regulatory regimes and include a normalisation for major events.[55]

The DPP reset process established new reliability caps that applied from RY2021 to RY2025. The next DPP reset will set new reliability targets from RY2026 to RY2030. At this stage, we continue to use the current caps for the new regulatory period from RY2026. Below the regulatory cap, we have established our own target. This target is based on our average performance from the prior three years (refer to Figure 79 and Figure 80).

The headroom between our internal target and the regulatory cap has reduced over that included in the 2021 AMP. This reflects the impact of extreme weather on our average (normalised) performance.

[54] These questions related to answering the phone, advice on planned outages, and advice on technical matters.
[55] The normalisation occurs when the rolling 24-hour period exceeded a defined threshold.

Figure 79: Unplanned SAIDI targets

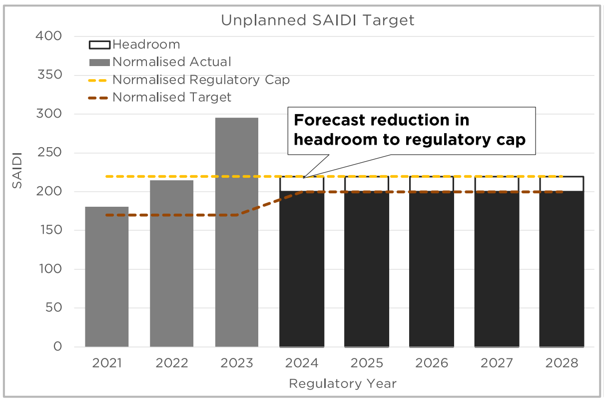
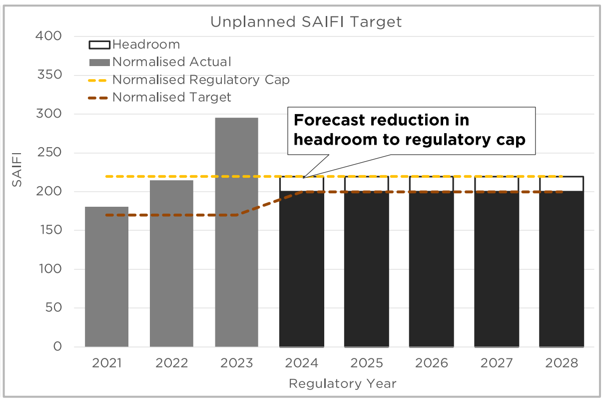


Figure 80: Unplanned SAIFI targets



8.4.2 Planned network reliability targets

The planned SAIDI and SAIFI regulatory cap changed in RY2021 and moved from an annual to a five-year cap. The cap increased significantly, reflecting the increase in planned work forecast by the industry. We also have planned SAIDI and SAIFI targets based on our prior average performance (refer to Figure 81 and Figure 82).

Figure 81: Planned SAIDI targets

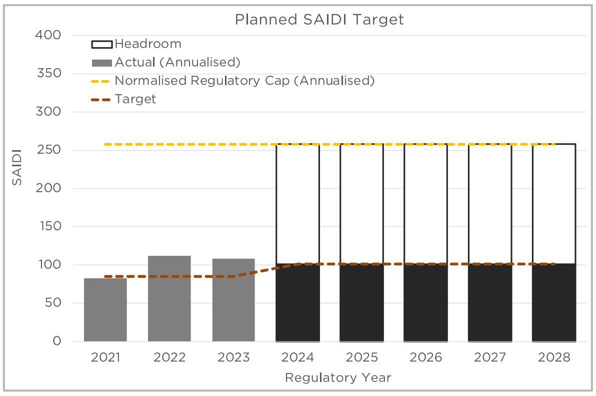
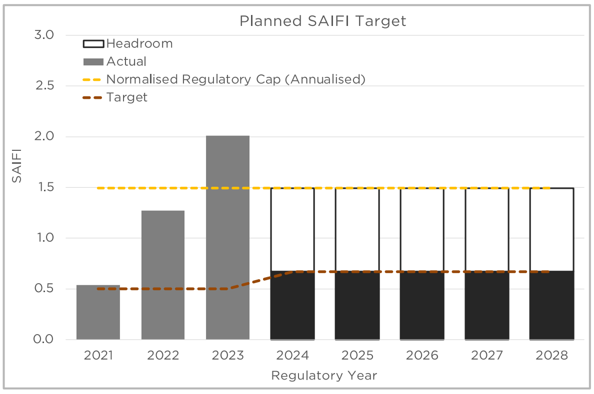


Figure 82: Planned SAIFI targets

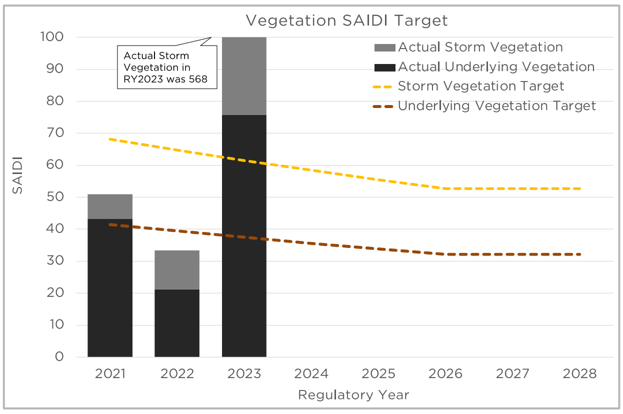


8.4.3 Vegetation outage targets

The impact of vegetation on the network and its increasing effect on network reliability has driven the need to monitor the performance in this outage category. During FY2021, additional outage categories were included in our fault management system to capture more information on the types of vegetation faults occurring. This data allows us to understand the causes of outages and target our expenditure and effort more effectively (refer to the asset lifecycle plans, vegetation, Section 11.23). In our 2021 AMP, we set targets for storm and underlying vegetation SAIDI.[56] The targets included a 5% improvement each year. These targets enable us to measure progress on vegetation management.

[56] In the 2021 AMP we set targets for vegetation SAIDI and SAIFI. Win this AMP, we have only included vegetation SAIDI as this is the focus of our vegetation management strategy and plan.

Figure 83: Vegetation SAIDI targets



8.4.4 Fault restoration time

The following measures determine how well Firstlight are doing at restoring supply following a fault:

Table 29: Fault restoration targets

Category	RY2021	RY2022	RY2023	RY2024+
Percentage of urban customers restored within 3 hours.[57]	>78%	>FY21	>FY22	>FY23
Percentage of rural customers restored within 6 hours.[58]	>75%	>FY21	>FY22	>FY23

The target has been set based on achieving a year-on-year improvement in restoration times over the next 5-years.

8.5 Asset management, utilisation and efficiency

Complimentary to the network reliability targets, measures concerning asset performance have been included. These measures should improve over time due to improvements in asset management practices.

8.5.1 Underlying asset fault rate

A measure of the underlying asset fault rate has been included. Inherent in operating a diverse and widespread distribution network are circumstances beyond Firstlight's control (or where controls are uneconomic that they are not worth implementing). Therefore, some outages have been removed from the performance measure data set, e.g. outages caused by lightning strikes and third-party interference. The resulting measure indicates the asset performance concerning areas that are generally under Firstlight's control (e.g. defective equipment, adverse weather, human error, wildlife, and adverse environment).[59]

Table 30: Underlying asset fault rate targets

Underlying asset fault rate (faults per 100km)	RY2021 to RY2026
110kV overhead lines	0.9
33/50kV overhead lines	3.64
11kV overhead lines	12.2

8.5.2 Defective equipment fault rate

To further measure the reliability of different types of assets, a range of asset-type performance measures have been established. An initial view of targets was included in the 2021 AMP. These

57 The baseline is based on the 75th percentile performance between FY2013 and FY2019.
58 The baseline is based on the 75th percentile performance between FY2013 and FY2019.
59 In the 2021 AMP, the target excluded wildlife and adverse environment. These have now been included.

have been revised based on more accurate asset failure data captured between RY2020 and RY2023. The initial targets reflect the average failure rate over that period.

Table 31: Underlying equipment fault rate targets

Faults per equipment type[60]	Unit of measure	RY2023 to RY2025	RY2026 to RY2028
Zone substation equipment	Per 1k units/year	<7.5	We are targeting a 10% improvement in failure rate
Pole (wooden)	Per 10k units/year	<7.4	
Pole (concrete)	Per 10k units/year	~0	
Pole (crossarm or insulator)	Per 10k units/year	<3.6	
Conductor (incl. jumpers and joints)	Per 100km/year	<1.6	
Underground cable (incl. termination)	Per 100km/year	<7.7	
Ground mount transformer	Per 1k units/year	<4.6	
Pole mount transformer	Per 1k units/year	<5.0	
Ground mount switchgear	Per 1k units/year	<0.9	
Pole mount switchgear	Per 1k units/year	<4.3	

These asset class performance targets are based on historical performance and have not been compared to industry standards or similar businesses. However, these are seen as important to set standards for individual assets, which significantly impact reliability performance.

8.5.3 Asset utilisation

Asset utilisation measures are defined by the following indicators:

- Asset per ICP = Value of RAB / No. of ICPs;
- Load factor = kWh's entering network during the year / (Max demand for the year x hours in the year);
- Capacity utilisation = Maximum demand for the year / installed distribution transformer capacity.

It should be noted that the network configuration predominantly determines the asset utilisation measures. Over the planning period, Firstlight expects to maintain a steady state position.

Table 32: Asset utilisation targets

Asset utilisation measures	RY2021 to RY2026
Asset per ICP	$6,472
Load factor	54%
Capacity utilisation	23%

8.5.4 Losses

The measurement of losses is a very broad measure of the efficiency of the network. With that said, reducing losses requires additional investment in assets.

Losses are measured as follows:

[60] Based on historical average

- Loss ratio = kWhs lost in the network during the year / kWh entering the network during the year

Table 33: Loss targets

Losses	RY2021 to RY 2026
Loss Ratio	9.5%

8.6 Delivery

Delivery measures cover two areas:

- The capturing of condition information to support asset health assessments;
- Completion of planned work.

8.6.1 Capturing of condition information to support the asset health assessment

Our 2021 AMP target was to complete all structure inspections by RY2024, zone substation switchgear by the end of RY2021 and ground mount distribution transformers and switchgear by RY2023. Pole mount transformers and switchgear are inspected when the lines are inspected, so they are due for completion by the end of RY2024.

8.6.2 Completion of planned work

We expect to achieve over 95% of planned work completion for system growth, asset replacement and renewal and reliability, safety and environment capex categories. We have set the target below 100% to account for individual project timing and budgeting variability.

8.7 Financial sustainability

The targets reflect the post-tax nominal WACC allowed in the DPP3.[61] The regulatory returns for the DPP4 have not been set.

Table 34: Targets for financial sustainability

Expenditure category	FY2021 to FY2025	FY2026 to FY2030
ROI (post-tax nominal WACC equivalent)	4.23%	TBC

[61] Commerce Commission, "[2019] NZCC12 Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path", 25 September 2019.

Part 3:

How we are implementing our asset management policy and strategy and achieving our service levels

9. Asset Management Roadmap

This section outlines our asset management roadmap and the progress we are making. The roadmap covers the asset management processes, systems, and information and asset management maturity. The roadmap is a key driver of non-network expenditure.

9.1 Introduction

We outlined our roadmap to improving asset management practices in the 2020 AMP and have been reporting on our progress in each subsequent AMP. In the AMP, we outline the revisions made to the roadmap in light of the recent acquisition by Firstgas Group and report on recent progress.

An overview of the asset management processes, systems, and information is incorporated. This section also includes details of the business support, system operations, network support opex and non-network capex. These expenditure categories are heavily influenced by the roadmap and the increasing economies of scope within Firstgas Group.

9.2 Asset Management Practice Improvements

9.2.1 Recap on the starting point

The original roadmap was prepared during RY2020, and much has changed since it was prepared. We are continuing with the program to improve the quality of the management and stewardship of the electricity network assets; however, the roadmap is being revised to reflect the adoption of systems and processes from Firstgas Group. The goals and targets included in this section reflect the outcomes of our initial review, and more will follow in the 2024 AMP.

9.2.2 Asset Management Improvement Roadmap

Our objective remains unchanged, which is to be a fully proficient asset manager. The progress has been slow due to the response to the cyclones of RY2023 and the change of ownership. However, being part of a large, well-established infrastructure owner will enable Firstlight to leverage established good practices within the Firstgas Group. The intention is to be a fully proficient asset manager by the end of RY2025.

Success will be measured through improvements in asset management maturity that are disclosed as part of the AMP and through achieving a series of measurable goals.

> The objective of the asset management roadmap is to transition Firstlight Network to a fully proficient asset manager by the end of RY2025

Table 35: Status of asset management roadmap goals

Goals	Due Date	Status
(a) To ensure that there is suitable information to support asset management decision-making	October 2020* October 2024+	Complete Significant progress was made. Only minor work is outstanding
(b) To prepare a comprehensive 2021 AMP that fully addresses the identified asset management issues and strategies	March 2021	Complete

Goals	Due Date	Status
(c) To have a robust system to provide assurance to the Board over the effectiveness of AM activities and compliance with regulations	March 2021	Complete
(d) To have a systematic and evidence-based asset management process	March 2022	Complete
(e) Develop the key elements of an asset management system consistent with ISO 55000, which are appropriate for Firstlight	~~March 2022~~ March 2025	Cyclones and the transition to Firstgas Group have slowed progress
(f) Achieve an overall assessment management maturity of 3, being a fully competent asset manager	~~March 2023~~ March 2025	AMMAT score has been improving. However, Cyclones and the transition to Firstgas Group has slowed progress

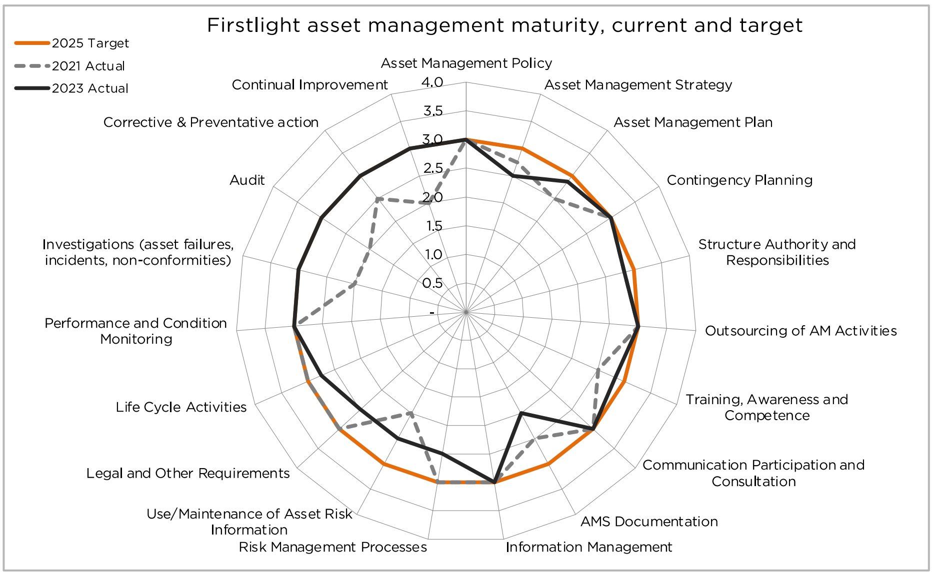
* For key assets classes of wooden poles, concrete poles, steel structures, distribution lines, and sub-transmission lines.
+ Other material asset classes.

The significant response to the cyclone events of RY2023 and the transition to Firstgas Group has delayed progress in achieving a maturity level 3. Firstlight anticipates that this will be achieved by the end of 2025. Targeting a maturity level of 3 is considered appropriate and consistent with current regulatory expectations for the industry.

9.2.3 Current Asset Management Maturity

We engaged an external consultant to complete the AMMAT assessment. Figure 84 shows the asset management maturity for RY2023. The score for RY2023 is 2.8, up from 2.7 in RY2021. There has been some movement in the scoring, partly due to the transition to new systems and processes. Overall, the improvements are positive, and the gaps are small (other than system documentation).

Figure 84: Asset management maturity (2023)



9.2.4 Targeted improvements in asset management maturity

The areas that require improvement relate to asset management strategy and system documentation, lifecycle activities, risk management, and compliance. With these improvements, we will be on track to achieve an AMMAT score of 3 by the end of RY2025.

For the remainder of RY2023 and RY2024, we will be focusing on the following items:

Table 36: Asset management improvement focus areas

Focus for RY2023 and RY2024	Status
Refining the asset strategy to fit under the Firstgas Group strategy	Initial work has commenced
Completing the inspection of material asset classes to achieve data accuracy scores of 3	Significant progress has been made, and only limited work is outstanding
Improve our asset management system documentation	Work to commence in RY2024
Improve the use of asset risk information and integrate with Firstgas Group risk processes	Work to commence in RY2024
Improve the controls over the delivery of our lifecycle plans	Work to commence in RY2024
Fully adopt Firstlight's legal and regulatory compliance program.	Initial work has commenced

9.3 Information systems

9.3.1 Core Information Systems

Firstlight Network information systems now comprise:

Table 37: Firstlight Network ' s primary information systems

System	Provider	Functionality	Data held
Enterprise resource planning	Maximo	• Asset management • Works management • Project management • Materials management and purchasing • HR • Finance • Business intelligence and reporting • Asset registers	• Asset health • Asset age • Asset attributes • Project costing • Asset financial information
Field Mobility	ODK	• Field mobility for contracting teams	• Asset condition
Geographical information system	ESRI	• Mapping and geospatial analysis	• Geospatial data • (Visibility of asset data held in Maximo)

In addition to the three core systems, Firstlight Network also operates a number of other systems that directly support the network business. These include:

Table 38: Firstlight Network's other information systems

System	Provider	Functionality	Data held
Risk Manager	Impac	• All aspects of risk management, H&S	• Risks, controls, incidents, etc.
Fault Database	Excel	• Recording of network HV outages	• Network outages • SAIDI and SAIFI
DNO asset health assessment	Excel	• Calculation of asset health as per the DNO Methodology	• Current asset health • Forecast asset health • Asset condition
Billing	Axos	• Billing	• ICP information (but no customer details) • Consumption • Demand (for demand customers)

System	Provider	Functionality	Data held
Demand forecasting model	Excel	• Forecasting of connections, consumption and demand	• Forecasts of connections, consumption and demand
Network modelling	PSS SINCAL	• Power system simulation and utilisation modelling	• Network connectivity model
Network modelling	LV Drop	• Low voltage design	• n/a
Substation management system	Various providers	• Remote access to the major substations for download of log information and reconfiguration of equipment, e.g. Siemens GE and Other	• Log and event information and protection settings
Line design	CATAN	• Structural engineering/line design	• Existing line designs, pole structure and component library
CAD	AutoCAD MicroStation	• Drafting for design drawings and schematics	• Schematics • Substation drawings
Drawing files	Access database	• Historic inspection records and as-built drawings	• Manual drawings for functionality
Filing system	Manual and electronic records	• Storage of data (i.e. property files)	• Historical asset condition and maintenance information

9.3.2 Cyber Security

Firstgas Group provides cyber security as part of the provision of the core technology platforms. Security measures include policies, audits, monitoring, and management of change procedures.

Firstgas Group has partnered with an information security consultancy and is committed to an ongoing cyber security improvement program. The expectation is that this program will identify critical and non-critical compliances that will lead to improvement opportunities.

9.4 Data Quality Improvements

Improving data quality is a continuing focus for the business. We have made significant progress since 2019 but have a few areas where improvements can be made (highlighted in orange in 39).

Determining the conductors' age, condition, and health is difficult, and we will be looking to adopt industry practices concerning conductor data as these evolve.

Table 39: Targeted Improvement in Data Quality

Asset class	2023 Data accuracy rating			Target Data accuracy rating by RY2025
	Asset attributes and quantity (schedule 9a)	Asset age (schedule 9b)	Asset health (schedule 12a)	
Zone Substation Transformers	4	4	4	4
Zone substation 3.3/6.6/11/22kV GM Circuit breakers	4	3	3	3
Concrete poles	3	2	3	3
Wood poles	3	2	2	3
Distribution open wire conductor	1	1	1	TBA
Distribution 3.3/6.6/11/22kV Switches and Fuses (pole mounted)	2	2	2	3

Asset class	2023 Data accuracy rating			Target Data accuracy rating by RY2025
	Asset attributes and quantity (schedule 9a)	Asset age (schedule 9b)	Asset health (schedule 12a)	
Distribution 3.3/6.6/11/22kV GM Switchgear	4	3	3	3
Distribution 3.3/6.6/11/22kV RMU	2	2	3	3
GM Transformer	4	2/3[62]	3	3
PM Transformer	2	2	3	3
Voltage regulators	3	3	3	3

9.5 System Improvements

Improving business processes, information quality, and analytical support for asset management is a continuing focus. We have just completed the transfer to Firstgas Group systems and have identified one system improvement project, as shown in Table 40 below. We will be undertaking a review of the systems over the next year, and this will likely identify further system developments.

Table 40: Proposed System Improvements

System improvements	Status
Implementing advanced asset management and expenditure analysis across Maximo, ESRI and FinOPS	It has not yet commenced. This has been deferred to RY2025.

9.6 System Operations and Network Support Costs

System operations and network support expenditure relate to the management and operation of the network. It includes the operations team, control centre, asset information team, engineering team and planning team (refer to Section 2.4). The human resource requirements primarily drive this expenditure. A large portion relates to direct staff costs. These costs are forecasts based on the forecast resources and internal costs, net of any capitalisation of design and project management work on capex projects. There have been some changes to the capitalisation and time-writing processes, which are discussed in Section 14.

These costs are primarily driven by the size and complexity of the network and the extent of the opex and capex works programs.

These costs now include software as a service expenditure (Saas), which has not been accounted for historically under this category.

Table 41: System operations and network support opex forecasts

Item	RY2024	RY2025	RY2026	RY2027	RY2028
System operations and network support	2,264	2,993	2,993	2,993	2,993

2023 Constant $000.

9.7 Business Support Costs

Business support costs relate to the corporate overhead costs required to operate Firstlight. These include corporate support from Firstgas Group (board, executive management, finance, treasury, regulatory and internal legal). It also includes corporate IT support, corporate IT Saas, insurance, HR, external legal, audit and assurance fees, professional advice and office costs.

62 2 for Wairoa region. 3 for Gisborne.

Most of these costs relate to salaries and wages and related staff costs (training, travel, accommodation etc.) Staff numbers, business scale, and the scope of the corporate IT systems drive these costs.

Firstlight benefits from the economies of scope of Firstgas Group. The costs would be materially higher if Firstlight were a standalone company.

Table 42: Business support opex forecasts

Item	RY2024	RY2025	RY2026	RY2027	RY2028
System operations and network support	4,000	4,102	4,102	4,102	4,102

2023 Constant $000.

9.8 Non-Network Capex

Non-network capex includes expenditure on items and assets such as vehicles, buildings, software, etc. These items are part of the cost of maintaining the network support function. Other assets, such as corporate IT infrastructure, phone systems, and shared corporate software, are managed by Firstgas Group and are recognised under business support opex.

9.8.1 Earthquake strengthening and refurbishment work

The Firstlight team resides in outdated office areas originally part of the Power Board depots. The offices in Wairoa were due for refurbishment and earthquake strengthening. It was decided to demolish the existing building and develop a new office in RY2026.

9.8.2 Vehicles, tools and safety equipment

Firstlight operates a fleet of cars, utility vehicles, fault vehicles, and one generator truck. There is an ongoing program of replacement for these vehicles. This replacement program averages $134k pa. over the next five years. The forecast has increased for RY2024 and RY2005 due to the aging of the fleet.

Firstlight maintains specialist test equipment and has forecast the ongoing replacement and upgrading of this equipment. The equipment includes protection relay test equipment, earthing sticks, fault locators, and other equipment used by the engineers and faultmen. Expenditure has increased to accommodate the renewal of several key pieces of test equipment, including fault locators and resistance/impedance testers.

The forecast expenditure in IS hardware was not previously included (as was a corporate charge under Eastland Group ownership). This is a general allowance for office-based IT hardware.

As noted in Section 9.3, IT systems are provided by Firstgas Group and the associated charges are included in business support costs.

Table 43: Non-network capex forecasts

Projects	RY2024	RY2025	RY2026	RY2027	RY2028
Wairoa office refurbishment	-	-	335	-	-
Routine office capex	107	21	21	21	21
Vehicle replacement	130	136	135	136	136
General asset and test equipment replacement	52	52	52	52	52
IS hardware	22	46	46	46	46
Total	**311**	**255**	**589**	**254**	**255**

2023 Constant $000.

Variances to the RY2022 forecasts are discussed in Section 14.

10. Asset Lifecycle Plans (Network Development)

This section describes the plans to develop the network to meet forecast load growth, improve the security and reliability of the network, improve resilience, and respond to the energy transformation.

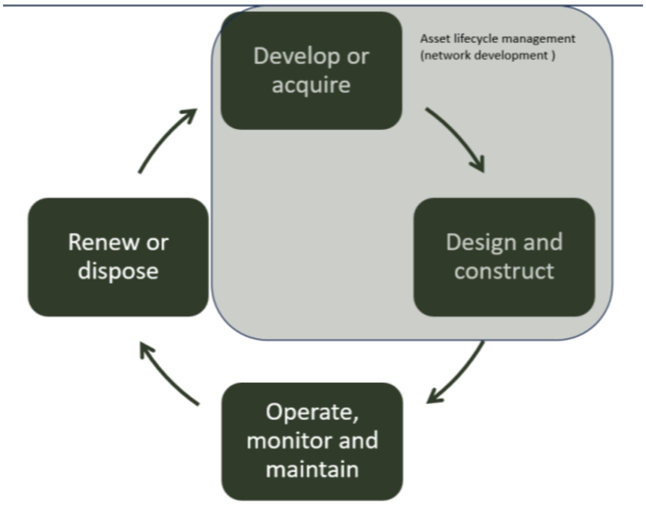
10.1 Introduction

This section identifies and discusses the *develop or acquire* phase of Firstlight's asset lifecycle. This section also covers some aspects of the *design and construct* phase.[63]

Firstlight's approach to network planning (i.e. whether to acquire or develop an asset) typically encompasses the following steps:

- Assessing the network (by network element) against the planning criteria to determine if there are indicators that development is required. This also includes consideration of the initiatives and actions within the asset management strategy (that relate to step-change growth and security and reliability enhancements);
- Where indicators are present, developing a concept solution, which considers alternatives, non-network solutions, energy efficiency, risk, and economic viability;
- Prioritisation of the concept solution against other projects;
- When the project makes it through the first three steps, it will be included in the AMP and progress to the detailed design and construction phase.

Figure 85: Phases of the asset lifecycle



In this section, the drivers for network development are covered, including:

- The alignment to the asset management strategy;
- An overview of the network planning criteria;
- Demand forecasts;

We then discuss the impact the drivers have on system development, including:

[63] A description of the phases of the asset lifecycle are provided in Section [x2].

- System developments to meet demand and security requirements;
- System developments to meet resilience needs;
- System developments to meet reliability requirements;
- Preparation for and responses to the energy transformation;
- A summary of expenditure forecasts.

10.2 Asset management strategy drivers

Firstlight's asset management strategy is a key driver, and the following initiatives are relevant for network development:

- The initiatives and actions to enhance resilience;
- Increasing the use of network automation (sectionalisers and reclosers) to minimise the impact of outages;
- Investigating opportunities for additional generator support;
- Ensuring the network can support the energy transformation and decarbonisation of the region;
- Developing alternative options to a network solution to provide capacity into Gisborne[64];

10.3 Network Planning Criteria and Standards

10.3.1 General Development Planning Criteria

The consideration of the need for network development is triggered when one or more planning criteria are reached. The planning criteria include capacity, security, reliability, voltage, and location, and are shown in Table 44 and Table 45 below.

The development of the solution requires an assessment of alternatives, an evaluation of risk, and the optimisation of timing. This typically involves engineering assessment to weigh up the factors and trade-offs, both when the solution is being developed and when the solution is prioritised against competing projects. A high-level overview of the decisions for the projects is provided later in this section.

Table 44: General planning criteria

Network element	Capacity Trigger	Security Trigger	Reliability Trigger	Voltage Trigger	Location Trigger
Subtransmission and transmission feeders	Load exceeds 66% of thermal rating more than 3,000 half-hours per year. Load exceeds 100% of thermal rating over ten consecutive half-hours per year.	Demand exceeds current security (refer to Table 45).	Fault rate above industry standards or identified as a worst performing feeder.	Voltage depression that cannot be compensated for at substations.	The load cannot be reasonably supplied by distribution configuration, requiring new subtransmission lines or cables and zone substation.
Zone substations	Max demand consistently exceeds 100% of the nameplate rating.	Demand exceeds current security (refer to Table 45).	Fault rate above industry standards.	Distribution voltage depression cannot be compensated for locally.	The substation is not efficiently located near the load.

[64] A base case network solution has been developed to increase network capacity into Gisborne.

Network element	Capacity Trigger	Security Trigger	Reliability Trigger	Voltage Trigger	Location Trigger
Distribution feeders	Load exceeds 66% of thermal rating more than 3,000 half-hours per year. Load exceeds 100% of thermal rating over ten consecutive half-hours per year.	Demand exceeds current security (refer to Table 45).	Fault rate above industry standards or identified as a worst performing feeder.	The voltage at the HV terminals of the transformer consistently drops below 10.5kV and cannot be compensated by the local tap setting.	The LV configuration cannot reasonably supply the load, requiring new distribution lines, cables, or substations.
Distribution substations	MDI reading exceeds 80% of the nameplate rating.	Not applicable.	Fault rate above industry standards.	The voltage at LV terminals consistently drops below 1.0pu.	The substation is not efficiently located near the load.
Low voltage system	LV is typically sized for voltage. Hence, constraints manifest as voltage drops.	Not applicable.	Fault rate above industry standards.	The voltage at consumers' premises consistently drops below 0.94pu.	Existing LV does not reach new consumers.

10.3.2 Security of Supply Standards

The commonly adopted security standard in New Zealand is the EEA Guidelines, which reflect the UK standard P2/5 developed by the Chief Engineer's Council in the late 1970s. P2/5 is a strictly deterministic standard, stating that "the amount and nature of load will have this level of security". A characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence to the standards can result in some degree of over-investment.

Whilst there is a deterministic security of supply standard, the application of the standard is subject to the consideration of the economics of the investment, given the probability of failure and cost of non-supply. Factors such as community need may also be considered where the project impacts the wider community, e.g. supply to water/wastewater pumping stations, hospitals and schools.

Firstlight's security standards are outlined in Table 45 below, providing the base security criteria applicable to the network.

Table 45: Firstlight's security of supply

Class	Range of group peak demand (GPD) MVA	No. Consumers	Security level	Contingent capacity	Time to restore after 1st event	Time to restore after 2nd event
A	More than 25MVA, i.e. transmission or subtransmission rings.	> 15,000	n-1	100%	Maintain 100% GPD less 12MVA. The remaining 12MVA is restored within 3 hours.	Repair time.
B	Between 12 and 25 MVA, i.e. small GXP, primary CBD & urban substations	7,000 to 15,000	n-1	100%	Maintain 100% of GPD.	Restore 90% of GPD within 3 hours and the remaining 10% in time to repair.

Class	Range of group peak demand (GPD) MVA	No. Consumers	Security level	Contingent capacity	Time to restore after 1st event	Time to restore after 2nd event
C1	Between 6 and 12 MVA, i.e. primary urban or industrial substations.	3,500 to 7,000	n	100%	Restore 75% of GPD within 15 minutes, restore 90% within 3 hours, and the remaining 10% in time to repair.	Restore 90% of GPD within 3 hours. The remaining 100% in repair time.
C2	Between 3 and 6 MVA, i.e. single Tx substations and urban meshed feeders	1,750 to 3,500	n	80%	Restore 75% of GPD within 30 minutes, 90% within 3 hours, and the remaining 10% in time to repair.	Restore 100% in repair time.
C3	Between 1 and 3 MVA, i.e. rural zone substation, meshed feeders.	500 to 1,750	n	67%	Restore 50% of GPD within 1 hour, 90% within 3 hours, and the remaining 10% in time to repair.	Restore 100% in repair time.
D	Less than 1MVA, i.e. rural feeders, urban spurs, distribution transformers	< 500	n	Refer to Note 1.	Restore 100% in time to repair.	Restore 100% in repair time.

Note 1: Refer to Firstlight's Consumer Service Standards for LV Network backup, dual distribution transformer capacity, or temporary supply criteria. Temporary options include constructing prefabricated OH lines, HV or LV flexible surface jumpers or 300kVA generator supplies.

10.3.3 Distributed Generation is an Alternative to Network Assets

Distributed generation can provide security and has been widely used on the network. Presently, there are eight large, embedded generators. Six of these are owned by Firstlight and are deployed to provide security for zone substations and remote rural feeders.

During the planning phase, generation is considered an alternative to investment in network assets to meet security requirements.

10.3.4 Distributed Generation (more generally)

Firstlight recognises the value of distributed generation for its contribution towards reducing demand, losses, and potential benefits to the consumer-owners. It is also recognised that distributed generation can have undesirable effects on the network, including increased fault levels, protection complexity, and new constraints and voltage issues.

Firstlight recognises the contribution from distributed generation and shares the benefits that arise from reducing Firstlight's costs (such as transmission investment costs or deferred investment in the network), provided the distributed generation is of sufficient size to offer real benefits.

Despite the potential for some undesirable effects, the development of distributed generation is actively encouraged, which will benefit both the generator and the network. As per the Electricity Industry Participation Code 2010 Part 6 (Connection of Distributed Generation), details on the necessary processes and information required to enable the connection of DG to Firstlight's assets are available on the Firstlight website (www.firstlightnetwork.co.nz).

Evaluation criteria include:

- Generator technical standards and operational impacts on the network
- Safety
- Metering
- Network benefits.

While case-by-case analysis is required, planning criteria regarding the maximum allowable injection into the network before exceeding voltage limits are listed in Table 46.

Table 46: Eastland Network's distributed generation injection criteria

Location	Nominal maximum generator export
Urban 50kV subtransmission	8 - 20 MW
Rural 50kV subtransmission	2 - 8 MW
Urban 11kV distribution	3 - 6 MW
Rural 11kV distribution	50% of the typical feeder load 50 - 500kW
Rural 11kV distribution near major substations	1 - 2 MW
Urban 400V Reticulation	100 - 200kW
Rural 400V Reticulation	8 to 50kW

10.3.5 Flexibility

Flexibility (the ability to modify generation or consumption patterns in reaction to an external signal, such as a change in price) plays an important role on the network to reduce peak demand. Firstlight uses traditional ripple control and generation technology to access flexibility on the network.

The concept of a flexibility market is under active development by the Electricity Authority.[65] A flexibility market would see Firstlight seek offers for firm demand reductions (or battery discharge or controllable generation) to defer capacity-driven investment. A flexibility market will allow distributed battery or other technology to contribute to demand reduction. Some flexibility arrangements have been established to defer capacity-related projects, but no active market exists.[66] Firstlight is monitoring the costs of flexibility arrangement and will consider these as alternatives to capacity-driven investment.

We discuss flexibility further in our preparation for the energy transformation in Section 10.12.

10.3.6 Other Non-Network Solutions

Firstlight has only utilised generation and traditional ripple control as alternatives to network assets. However, the costs of new, alternative technology (e.g. large-scale batteries) continue to be monitored, and we will issue requests for information and proposals when we believe that viable alternatives are available in the market.

10.3.7 Energy Efficiency

The current target is to maintain the network loss ratio consistent with the historical average, and given the rate of network demand growth, no specific loss reduction projects are planned.

From a planning perspective, the energy efficiency planning criteria (which are considered in the concept or detailed design phase) are:

65 https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/consultation/regulatory-settings-to-support-non-network-solutions-and-flexibility-services/

66 https://www.auroraenergy.co.nz/news/2021/aurora-energy-and-solarzero-partner-to-meet-future-growth-in-upper-clutha/

Table 47: Firstlight's planning criteria for losses

Network element	Design losses	Maximum operating losses
Transmission and subtransmission feeders	1%	2%
Zone substation transformers	1%	2%
Distribution feeders	3%	5%
Distribution transformers	2%	4%
LV distribution	3%	6%

In addition, capacity and voltage triggers are also a proxy for energy efficiency as they seek to mitigate heavily loaded feeders, which has the effect of managing losses to within acceptable levels. Encouraging distributed generation also contributes to loss reduction, where the generation is connected close to the load.

10.3.8 Project Prioritisation Criteria

The prioritisation of projects (initially at the concept solution phase) occurs as the AMP is finalised. The prioritisation considers a range of factors, including:

- Elimination of risk (where priority is also given to projects that eliminate or minimise critical risks or significant health and safety risks);
- Connection of consumers (typically, a consumer contribution ensures the connection is economic for Firstlight);
- Business benefits (where priority is given to improving reliability and security);
- Deliverability.

The extent to which projects are progressed within a regulatory year may be constrained by regulatory expenditure allowances (to the extent that these do not impact safety or materially impact risk). However, exceeding regulatory expenditure allowances or applying for a customised price path should the need arise.

10.4 Demand Forecasts

10.4.1 Introduction

Network demand (not energy consumption) and consumer connections are the key drivers of network development as the network needs to be expanded to supply new consumer, and/or the existing assets need to be augmented to supply growing demand. This section describes the drivers and forecasts for connections, consumption and demand. A baseline forecast has been prepared that has been used as the basis for evaluating growth projects.

Baseline forecasts include a "prudent planning margin" added to regional demand forecasts to ensure that the network can respond to a modest increase in industrial load (either new connections or electrification of process heat).

10.4.2 Historical Connection, Consumption, and Maximum Demand Trends

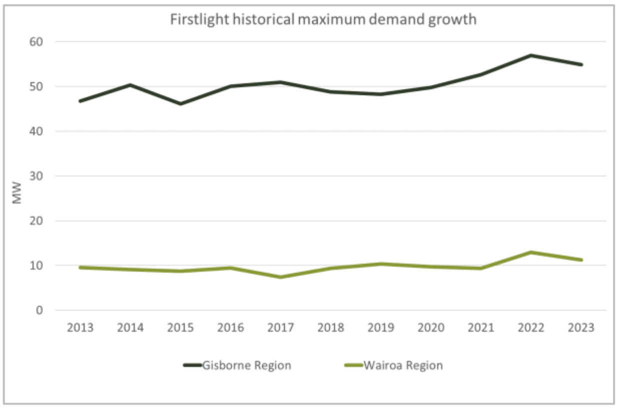
Since 2013, Firstlight has experienced minor consumer connections growth, with compounding annual growth rates (**CAGR**) being 0.38% p.a. for the Gisborne region and 0.25% for the Wairoa region.

The annual consumption growth rate has been 0.09% p.a. and 0.56% p.a. for Gisborne and Wairoa respectively. Consumption per consumer has declined since 2013, sitting at (0.2%) p.a. and (0.5%) p.a. for Gisborne and Wairoa respectively.

The maximum demand[67] growth rate has been 1.6% p.a. and 1.7% p.a. for Gisborne and Wairoa respectively, since RY2013 (refer to Figure 86).

Firstlight continues to be a winter-peaking network, with the maximum demand typically occurring between June and August.

Figure 86: Firstlight's historical maximum demand[68]



10.4.3 Drivers of Demand Growth

In preparing the baseline consumption and demand forecasts, the following drivers are considered and detailed later in this section:

- Consumer connection growth;
- Energy efficiency improvements;
- Change in baseline ADMD;
- Allow for industrial growth;
- The uptake of electric vehicles;
- The installation of solar PV and batteries.

Consumer Connection Growth

For the Gisborne region, the connection growth forecasts for the planning period are 0.57% for residential, 0.28% for commercial, and 0% for industrial consumer. The residential growth rate reflects a continuation of recent trends (where growth has been higher in the past five years). The higher commercial growth rate (compared to the historical trend) is more reflective of recent growth in that sector. The forecasts equate to 111 new consumer each year. Schedule 12c(i) contains further details.

For the Wairoa region, the connection growth forecasts for the planning period are 0.31% for residential, 0.15% for commercial, and 0% for industrial consumer. The residential growth rate reflects a continuation of recent trends, which have seen very modest growth. The commercial growth rate is more reflective of recent growth in that sector. The forecasts equate to 13 new consumer each year. Schedule 12c(i) contains further details.

Energy efficiency improvements

There continue to be opportunities to improve energy efficiency, and it is assumed that the current rate of improvement continues over the forecast period (which is a baseline[69] reduction in

[67] This is the maximum half hour demand at GXPs plus embedded generation, and net of controlled load.
[68] The maximum demand is based on a 2-hour rolling average, which is approximately 98% of the peak ½ hour period.
[69] Before small-scale distributed generation, EVs, and electrification fo domestic gas).

consumption per consumer of 0.9% p.a. for Gisborne and 0% for Wairoa[70]). Energy efficiency improvements only impact consumption and do not impact peak demand.

Change in baseline ADMD

Based on historical trends, we forecast changes in per consumer after diversity maximum demand (**ADMD**). The ADMD CAGR was 1.23% p.a. for Gisborne and 1.49% p.a. for Wairoa since 2013. The growth in ADMD has been higher in the last five years. This indicates that consumer demand is getting slightly more "peaky".

A range of factors will be driving the increase in ADMD, including (to a small degree) the charging of EVs, the electrification of gas and the reduction in hotwater demand response. The charging of EVs is now being modelled separately. We have sought to remove the influence of EVs by reducing the ADMD growth rate to 50% of the recent trend.

The electrification of gas and reduction in hotwater demand response will be separately modelled in the 2024 AMP, and we will further reduce the baseline ADMD growth rate at that time.

Allowance for industrial growth

We see two possible drivers of industrial growth:

- Wood processing;
- Electrification of process heat.

The predominant source of economic growth for the region is expected to be forest harvesting. The Ministry of Agriculture and Forestry's forecasts of the total recoverable volume of logs through to 2040 indicate current log volumes are expected to triple to around 2.5 million m^3 within five years and increase to ~3.5 million m^3 approximately ten years after that.

The "best guess" is that any expansion in wood processing would occur at the Matawhero substation, where the major wood processor is currently based.

We have surveyed our major consumers' intentions concerning the electrification of process heat, which indicated the current interest in electrifying industrial process heat was low; however, we recognise that things can change rapidly.

Given the difficulty in forecasting industrial growth, no new industrial consumer, expansion of existing industrial plants, or electrification of process heat are included in the baseline forecasts.

However, we recognised that responding to industrial consumer growth is necessary, particularly concerning supporting New Zealand's decarbonisation efforts. A prudent planning margin of 4MW has been applied to the Gisborne regional forecasts and 1MW to the Wairoa regional demand forecasts to cater for potential growth.

Electric Vehicles

A key factor influencing future electricity consumption is the uptake of EVs. Recent literature predicts parity between petrol/diesel and electric light vehicles over the coming years.[71] EV sales have been growing, and EVs and PHEVs now represent 11.75% of the light vehicle fleet and 23.5% of new vehicle sales.[72]

There is a policy drive to decarbonise New Zealand, and we believe this direction will continue regardless of which major party is in Government. At a national level, Firstlight has utilised

[70] Wairoa's consumption per consumer has been increasing over the past 10 years. The 5-year CAGR was 2.3%. Our forecasts reflect a halt in the consumption growth.

[71] https://www.ena.org.nz/resources/electrification-of-nzs-energy-needs/document/1231. Spaere is predicting cost parity by CY2025.

[72] https://evdb.nz/ev-percentage-nz and https://evdb.nz/ev-new-cars

Transpower's Whakamana i te Mauri Hiko, "accelerated electrification" scenario as an appropriate reference forecast.

The uptake of EVs will be consistent with regional income and GDP per capita. Firstlight supplies a region with the second lowest income distribution (the proportion of households with greater than $100k in income)[73]. Hence, it is likely that the uptake of EVs across our region will lag behind national trends. EV uptake is estimated to be around 70% of the accelerated electrification scenario for the Gisborne region and around 35% for the Wairoa region. This assumption will be reviewed periodically to ensure that Firstlight's assumptions are correct and forecast and consumption demand forecasts will be updated.

The Whakamana i te Mauri Hiko forecasts use a low ADMD contribution from controlled EV charging.[74] Given our region's low response to demand response signals, we used internal estimates of the extent of charging at home, work, and through commercial paid rapid charging stations that resulted in a controlled impact of 0.4 kW per EV (this reflects 4% of vehicles being charged coincident with the daily peak). Despite the higher peak contribution, it is assumed that there will be smart control of these devices that minimises charging at peak time (be this via the flexibility market or through consumers responding to pricing incentives).

This translates into:

- Around 6,300 EVs in the Gisborne region by RY2033 consuming 12.9 GWh and causing an increase in peak demand of 2.8 MW;
- A little under 760 EVs in the Wairoa region by RY2033 consuming 1.5 GWh and causing an increase in peak demand of 0.34 MW.

Figure 87: Firstlight's estimate of EV consumption

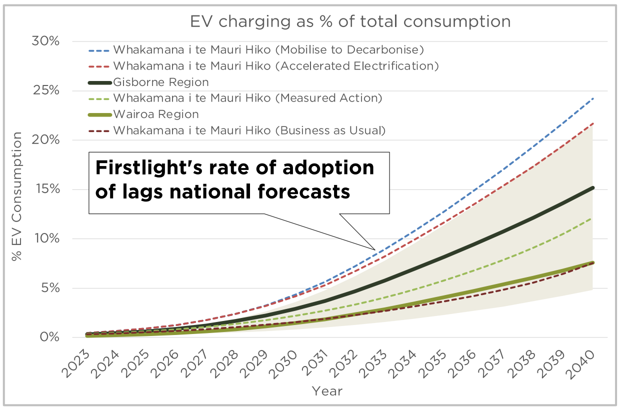
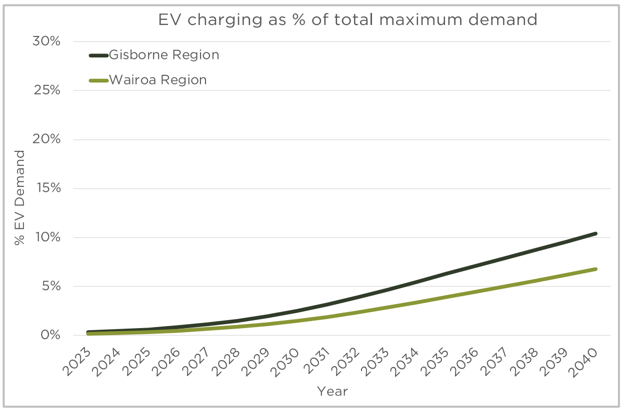


Figure 88: Firstlight's estimate of EV demand



There is a risk that EV charging flexibility will be used to respond to energy market needs (and not to network peak demand needs). Should this be the case, EV demand in RY2023 will increase to 9.0 MVA (a 180% increase). We are undertaking further work and will include controlled and uncontrolled forecasts in the 2024 AMP.

Solar PV and Batteries (DERs)

The economics of DERs for Firstlight's residential consumers have previously been modelled by applying solar radiation, consumption, and tariff data, and the analysis indicates for those consumers who have the necessary real estate and funding, the economics will:

- Become generally viable within the next 2-3 years for PV DERs;
- Become generally viable within the next 7-8 years for PV and battery DERs.

73 Source: MBIE regional economic activity tool.
74 0.061 kW in 2035 and 0.131 kW in 2050.

For the forecasts in this AMP, we used the forecasts prepared by Transpower in their Whakamana i te Mauri Hiko report and adjusted Transpower's accelerated electrification forecasts for DERs for factors relevant to Firstlight's regions.

Notwithstanding the economics, DERs will not be available to everyone over the coming 15 years. Factors that could impact uptake include:

- The ability to fund the system's capital costs;
- Apartments and terraced housing;
- Roofing material, construction and age;
- Site-specific issues (shading from neighbours and trees);
- Tenant/landlord barriers to technology uptake.

For Firstlight, we believe applying the funding and tenant/landlord constraints will suppress uptake well below the Whakamana i te Mauri Hiko forecast. We have reduced Transpower's accelerated electrification uptake assumptions by 10% and 50%, respectively, for the Gisborne and Wairoa regions. The impact of DERs on consumption is shown in Figure 89 below. These forecasts equate to 9% and 5% DER penetration rates in the Gisborne and Wairoa regions by RY2033.

Also, the forecast is the impact DERs will have on maximum demand. These forecasts represent the impact of battery discharge at peak times (applicable to installations with batteries installed, estimated to be 22% by 2031).

Figure 89: Firstlight's DERs forecast consumption

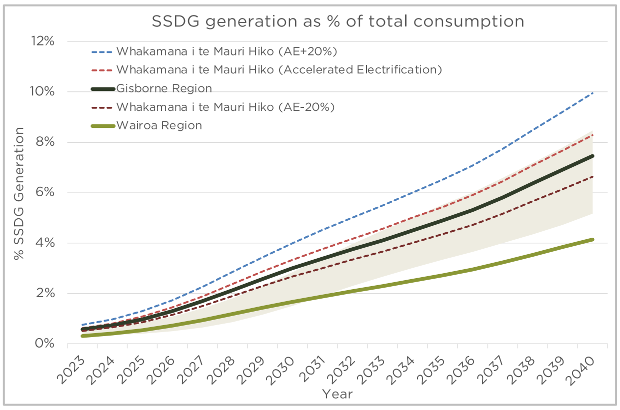
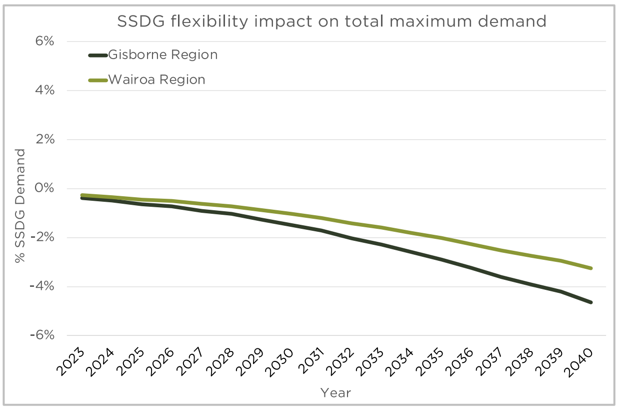


Figure 90: Firstlight's DERs impact on demand



It is assumed that the contribution to reducing peak demand will require a working flexibility market or time-off-use tariffs to incentivise the use of stored energy at peak times.

Schedule 12c(i) contains further details on forecast DER growth.

10.4.4 Baseline Growth Forecasts

The baseline growth forecasts are shown in Figure 91 to Figure 96. These forecasts cover connections, consumption and demand for the Gisborne and Wairoa regions.

Concerning the demand forecasts:

- For Gisborne, demand has increased over that forecast in our 2021 AMP due to the demand growth from RY2020 to RY2023 being higher than the previous forecast and higher ADMD growth than the previous forecast, offset by slightly lower EV demand growth. The forecast demand growth over the planning period for Gisborne is 1.4% p.a. (above the 1.2% in our previous 2021 AMP forecast);

- For Wairoa, demand has increased over that forecast in our 2021 AMP for the same reasons as Gisborne. The forecast demand growth over the planning period for Wairoa is 1.0% p.a. (above the 0.5% in our previous 2021 AMP forecast).

Figure 91: Gisborne region's demand forecast

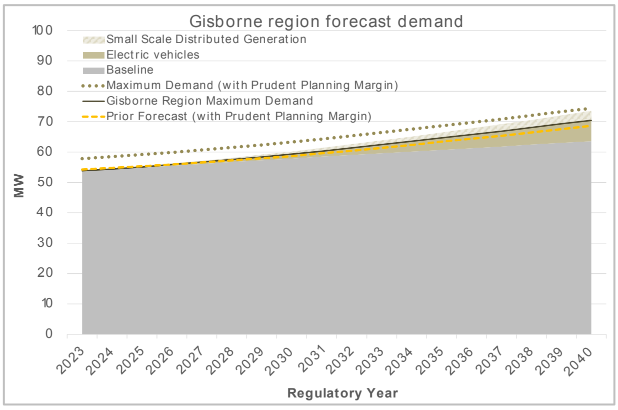


Figure 92: Gisborne region's consumption forecast

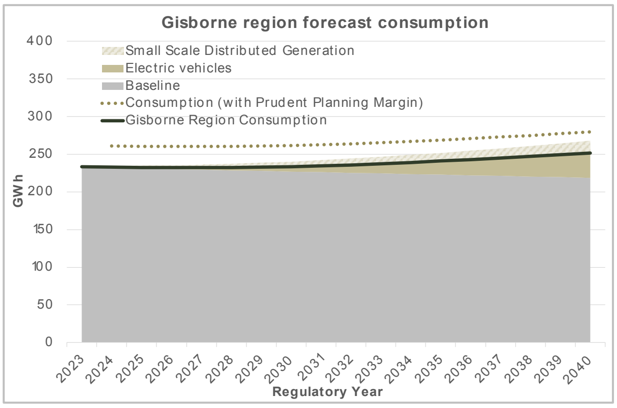


Figure 93: Gisborne region's consumer connection forecast

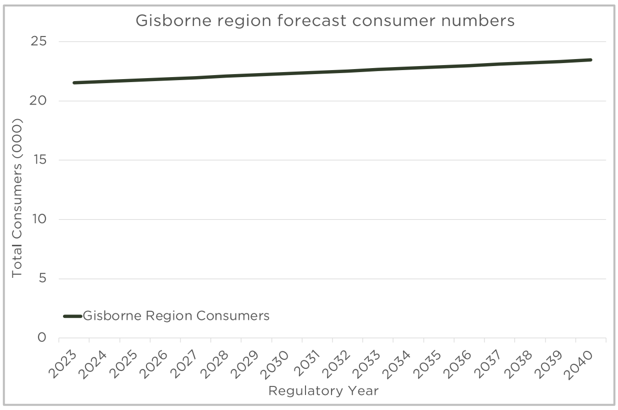


Figure 94: Wairoa region's demand forecast

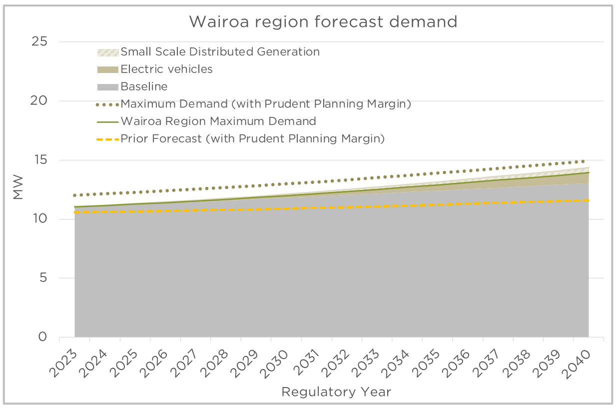


Figure 95: Wairoa region's consumption forecast

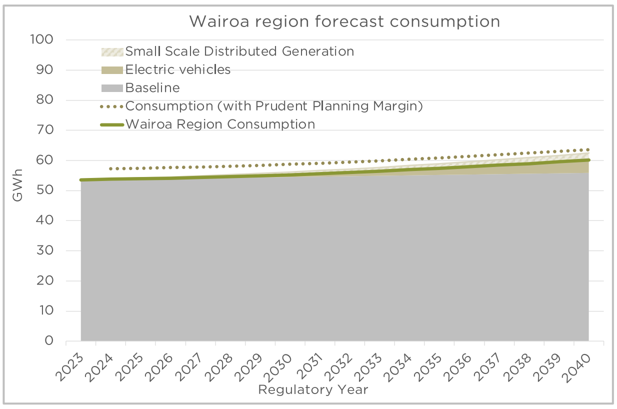
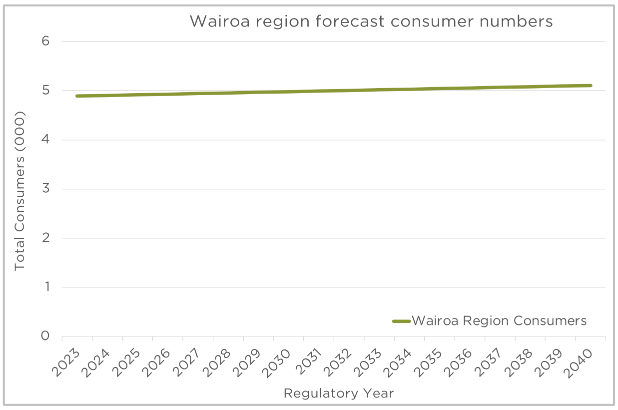


Figure 96: Wairoa region's consumer connection forecast



Schedule 12c(ii) contains further details of baseline forecasts.

10.4.5 Potential for Step-Change Industrial Growth

There continues to be discussion concerning significant industrial growth in the region. No forecast demand increase beyond the 5 MW prudent planning margin is being considered. However, in Section 10.7.3 we have discussed how to respond should step-change growth occur at 10MW, 20MW or 30MW.

10.4.6 Application at a Zone Substation and Feeder Level

The forecasts in Figure 91 to Figure 96 have been prepared at a regional level. However, the demand growth drivers also need to be considered at a zone substation and distribution feeder level. A demand growth rate has been applied for each zone substation and feeder based on the factors influencing growth at that substation. These have been prepared separately for Gisborne and Wairoa and are shown in the Tables below.

Table 48: Gisborne's zone substation and distribution feeder growth drivers

Growth rate type	Annual growth rate	Connection growth	EV penetration	DERs penetration
Decline	(0.5%)	Declining	Below baseline	Below baseline
Flat	0.0%	Below baseline	Below baseline	Below baseline
Low	0.5%	Below baseline	At baseline	At baseline
Medium	1.0%	At baseline	At baseline	At baseline
High	2.0%	Above baseline	Above baseline	Above baseline

Table 49: Wairoa's zone substation and distribution feeder growth drivers

Growth rate type	Annual growth rate	Connection growth	EV penetration	DERs penetration
Decline	(0.5%)	Declining	Below baseline	Below baseline
Flat	0.0%	Below baseline	Below baseline	Below baseline
Low	0.2%	Below baseline	At baseline	At baseline
Medium	0.5%	At baseline	At baseline	At baseline
High	1.0%	Above baseline	Above baseline	Above baseline

10.5 Consumer Connections, minor network upgrades, and asset relocations

10.5.1 Consumer connections

Where assets are required to be installed to facilitate a new, upgraded, or altered consumer connection, Firstlight's policy is that the cost responsibility resides with the consumer. Accordingly, most consumer connection expenditure is funded by consumers who engage directly with authorised contractors to carry out the required work, with the ownership of network assets being vested to Firstlight upon completion. If Firstlight contributes to the connection assets, these are typically recorded as vested assets.

The forecast for consumer connection capex is higher than historical levels due to the impact of inflation on connection costs and our expectation for higher connection growth (refer to Table 50). The forecast for vested assets is consistent with historical averages (refer to Table 50). Firstlight doesn't typically receive capital contributions. These forecasts are based on historical averages. Hence, actual expenditure in any year could vary materially.

Table 50: Consumer connection capex, capital contributions, and vested assets forecasts[75]

Expenditure category	RY2024	RY2025	RY2026	RY2027	RY2028
Consumer connections	140	117	118	119	121
Capital contributions	-	-	-	-	-
Vested assets	500	500	500	500	500

2023 constant $000

10.5.2 Minor network upgrades (in response to consumer connection or changes in demand)

The connection of new consumers or increased demand from existing consumers requires upgrading upstream assets. We forecast the upgrading of various assets, including network line extension to serve new load/areas, as shown in Table 51. These forecasts are based on historical averages, adjusted for the higher growth experienced, which we forecast will continue. The forecasts in this AMP are $90k p.a. higher than those included in the 2022 AMP.

Table 51: System Growth Capex to Support Consumer Connection and Demand Increases

Expenditure category	RY2024	RY2025	RY2026	RY2027	RY2028
System Growth[76]	545	630	629	630	631

2023 constant $000

10.5.3 Asset relocations

In this AMP, we have included an estimate concerning asset relocations (refer to Table 52). These forecasts are based on historical averages. Hence, actual expenditure in any year could vary materially.

Table 52: Asset Relocations

Expenditure category	RY2024	RY2025	RY2026	RY2027	RY2028
Asset relocations	51	51	51	51	51

2023 constant $000

75 Forecasts in constant 2023 dollars (000)
76 This covers switchgeat upgrades, distribution transformer upgrades, and network extensions.

10.6 System Developments to Meet Demand and Security Requirements

This section describes the zone substation and distribution feeder development projects to meet the forecast demand growth and system security requirements.

The proposed developments are detailed in two parts:

- The *options being considered*, which indicate the potential solutions that are under consideration. The exact solution has not yet been determined, and these projects are not included in the expenditure forecasts;
- The *proposed solution*, which is the recommended solution to resolve the demand growth or security issue. The recommended solution is included in the expenditure forecasts.

10.6.1 Zone Substation (including subtransmission feeders) security assessment and enhancements.

The analysis and projects in this section contribute to asset management strategy #4.

Evaluation against security planning criteria

Table 53 evaluates whether the target security levels are being met at a substation level (including the upstream subtransmission feeders) for the forecast loads over the planning period.

There are no changes in the required security.

Table 53: Substation security assessment

Substation	Required security	RY2033 Forecast security	Assessment of security based on forecast demand growth over the planning period	Additional provision for security
Gisborne Regional Substation	A	A	Demand is forecast to exceed the 110kV line firm capacity during shoulder periods by around RY2027. Transformer firm capacity is forecast to be exceeded by around RY2030.[77]	Refer to Section 10.7
Carnarvon Substation	B	B	Demand is forecast to be about 62% of installed capacity and 66% of contingent capacity by RY2033.	None required
JNL Substation	C1	C1	Forecast demand is within 11kV support capacity from adjacent Matawhero and Parkinson Substations.	None required
Kaiti Substation	C1	C1	Demand is forecast to be about 69% of installed capacity and 108% of contingent capacity by RY2033.	Refer to the Massey Substation project in Table 54
Makaraka Substation	C1	C1	Demand is forecast to be 69% of installed capacity and 132% of contingent capacity by RY2033.	Refer to the Massey Substation project in Table 54
Matawhero Substation	B	B	Demand is forecast to be 23% of installed capacity and 34% of contingent capacity by RY2033. This security level for this substation is higher than implied by the current load levels.	None required
Ngatapa Substation	C3	C3	Demand is forecast to be 19% of installed capacity and 32% of contingent capacity by RY2033.	None required

[77] Including the prudent planning margin, before the thermal upgrade of the 110kV line. Note: the security and capacity margin included in the Appendix exlcudes the prudent planning margin.

Substation	Required security	RY2033 Forecast security	Assessment of security based on forecast demand growth over the planning period	Additional provision for security
Parkinson Substation	B	B	Demand is forecast to be 36% of installed capacity and 39% of contingent capacity by RY2033.	None required
Patutahi Substation	C1	C1	Demand is forecast to be 33% of installed capacity and 81% of contingent capacity by RY2033.	None required
Pehiri Substation	C3	C3	Demand is forecast to be 18% of installed capacity and 37% of contingent capacity by RY2033.	None required
Port Substation	C1	C1	Demand is forecast to be 66% of installed capacity and 103% of contingent capacity by RY2033. The forecast security for this substation was previous B, which reflected this changing to an N-1 substation and the load transfer from the adjacent substation. This approach has changed, so the forecast security remains the same.	Refer to the Massey Substation project in Table 54
Puha Substation	C2	C2	Demand is 42% of installed capacity and 140% of contingent capacity. However, peak demand is very infrequent.	Refer to the Puha Substation (Ngatapa - Matawai 11kV Line) project in Table 54
Ruatoria Substation	C3	C3	Demand is forecast to be 31% of installed capacity and 77% of contingent capacity by RY2033. Demand is now at capacity for the diesel generator during winter months. Demand curtailment will be required if the 11kV backfeed is unavailable.	None required
Te Araroa Substation	C3	C3	Demand is forecast to be 47% of installed capacity and 94% of contingent capacity by RY2033. Demand is now at capacity for the diesel generator during winter months. Demand curtailment will be required if the 11kV backfeed is unavailable.	None required
Tokomaru Substation	C3	C3	Demand is forecast to be 47% of installed capacity and 98% of contingent capacity by RY2033. Forecast demand is within back-feeding capability.	None required
Tolaga Substation	C3	C3	Demand is forecast to be 26% of installed capacity and 73% of contingent capacity by RY2033. Forecast demand is within the combined capacity of the diesel generator and 11kV back-feeding capability. Demand curtailment will be required if the 11kV backfeed is unavailable.	None required
Blacks Pad Substation	C3	C3	One 1MWe diesel generator is used to support both load and voltage. Demand is now at capacity for the diesel generator during winter months. Demand is 116% of contingent capacity.	Refer to the Blacks Pad and Mahia substations project in Table 54

Substation	Required security	RY2033 Forecast security	Assessment of security based on forecast demand growth over the planning period	Additional provision for security
Wairoa Substation (110/11kV)	B	B	Maximum demand currently sits slightly above 10MW, equal to the transformer capacity. With the addition of the prudent planning margin, forecast demand is above the capacity of the transformers.	Refer to the Wairoa Substation project in Table 54
Wairoa Substation (33kV supply to Blacks Pad)	C2	C2	Demand is forecast to be 18% of installed capacity and 223% of contingent capacity by RY2033. The Blacks Pad generator provides contingent capacity for this supply.	Refer to the Blacks Pad and Mahia substations project in Table 54
Kiwi Substation (Wairoa)	C2	C2	Three 11kV feeders are supplying the Kiwi substation from the Wairoa substation. There is sufficient capacity to supply this substation for the forecast period.	None Required
Tahaenui Substation	C3	C3	Demand is forecast to be 42% of installed capacity and 32% of contingent capacity by RY2033.	None required
Waihi Substation	D	D	This is the connection for Waihi Hydro. Demand is forecast to be 70% of installed capacity. There is no contingent capacity. The connection meets consumer requirements.[78]	None required
Tuai Substation	D	D	Forecast demand will never merit any alternative supply other than the possibility of relocating a diesel generator during a prolonged outage.	None required

Zone substation security development options under consideration

There are no options under consideration.

Proposed zone substation security development projects

Table 54 summarises the proposed substation security development projects in our expenditure forecasts.

Table 54: Proposed substation development projects

Substation	Issue	Proposed solution	Alternatives considered
Gisborne Transmission Substation	This is our most significant development project. Refer to section 0 below.		
Wairoa Substation	The 10MVA transformer capacity is insufficient to meet forecast demand, including the prudent planning margin. 2.5MW of firm distributed generation capacity is used to provide the capacity needed to meet forecast demand.	External consultants have been engaged to explore options and optimise network configuration for the Wairoa region. **RY27 – RY29 $1.1m** **RY31 – RY33$1.9m**	• Alternative and proposed solutions are still in development.

[78] This was previously at C2. However consumer requirements are for N (i.e. D) security.

Substation	Issue	Proposed solution	Alternatives considered
Kaiti, Port, and Makaraka Substations	These three substations are single transformer banks that supply a large area of the Gisborne township. Backup supply to all three substations is via 11kV links. Currently, restoration time for 100% of consumers is > 1 hour and involves complex manual switching operations. This shows that there is limited contingent capacity at all three substations. Forecast contingent capacities of the substations show that all three are above 100% contingent capacity in RY2033. The levels for Kaiti, Port and Makaraka are 108%, 103% and 132% respectively.	It is proposed that a 50/11kV zone substation be re-established at the Gisborne substation (the Massey substation) to supply the area, which will lighten the loads on the neighbouring substations (Port Makaraka and Kaiti). Project benefits include: • Existing infrastructure can support the loads from this substation (as some cabling already exists from prior work). • Sectionalisation of some of the larger urban feeders. • Reduction in response time. **Budget: $1.9m** **Schedule: RY2026-RY2028**	• Do Nothing (will still have the contingent capacity issues); • Install a second transformer at the three substations to increase the security (considered too costly as the installation and life cycle costs would make the project uneconomic).
Blacks Pad and Mahia substations	The two key issues are: • Peak period demand is above transformer capacity • Voltage is approaching planning criteria limits. These issues are constraining growth in the area. Network load flow studies and SCADA show that the Mahia feeder's voltage is reaching planning criteria levels. The Mahia Peninsula is supplied by a 33kV line from the Wairoa substation, which runs to Blacks Pad (roughly 10km from the Mahia township). Blacks Pad has a 1.5MVA (non-tapped) IMP transformer installed in 2000. Since this installation, the load in the area has remained stagnant due to the limitations on the network. The peak loads in the area are infrequent but are approaching 1.6-1.7MVA. A 1MWe diesel generator outside the Mahia township offsets the load during peak periods (less than 1% of the year).	The 33kV line supplying Blacks Pad is proposed to be extended 4-5km towards the Mahia township, where a new zone substation will be built. The new substation will be composed of a 2.5MVA transformer with three feeders. The Mahanga load (150-200kVA) will be separated from the Mahia feeder. This project has historically been deferred due to land issues. We are yet to finalise the line route. We are looking at options for land leasing or over-building our existing 11kV. Project benefits include: • Increasing capacity for the Mahia area, which will allow for development in the area; • Sectionalise the Mahia feeder (historically a large contributor to unplanned SAIDI and SAIFI), which will minimise the effect outages have on our network; • Increase the voltage in the area **Budget: $2.6m** **Schedule: RY2023-RY2025** Note: This project has commenced (after a 2-year	• Do nothing (will still have reliability, voltage and load issues); • Install capacitor bank at Mahia, which is to be used for peak loads (this is not economically viable, doesn't enable additional load which will be used to offset costs); • Replace the existing 1.5MVA transformer with a 2.5/5MVA unit (but this doesn't solve the voltage problems).

Substation	Issue	Proposed solution	Alternatives considered
		delay), and the budget has increased by $350k.	
Puha Substation (Ngatapa - Matawai 11kV Line)	Puha substation is built to supply the Matawai/Te Karaka and surrounding rural settlements southwest of Gisborne. The substation is supplied from a ring-fed 50kV subtransmission line, providing backup should one of the lines fail. A 5MVA transformer supplies the area. A 1MVA generator is connected at the substation and provides most of the contingent capacity. Peak loads for the Puha substation are reaching above 2MVA. 300-400kVA can be supplied from 11kV ties to the substation feeders, but the entire load cannot be fully supported for peak times. Summary of issue: Contingent capacity is insufficient to supply loads at peak times.	An 11kV line from the Ngatapa substation is proposed to be constructed underneath the 50kV Ngatapa - Puha line and connected to the Matawai feeder. This will require an additional 3.5km of line to be built. The line will have a capacity of c.2MVA and will provide the additional contingent capacity needed for the full contingent capacity of the Puha substation. In addition to this benefit, it provides a second supply for the Matawai feeder, currently supplied through a single critical line (> 400 connected ICPs). The Matawai line contributes an average of 9 unplanned SAIDI annually, and this project can potentially reduce this by at least a third. **Budget: $520k** **Schedule: RY2026** Note: This project has been delayed 12 months, and the budget has increased by $200k.	• Do nothing (maintain the same levels of reliability for the Matawai feeder and Puha contingent capacity below peak substation loads). • Install a 2.5MVA zone substation using the existing 50kV (Ngatapa - Puha) line. The cost of these alternatives is not considered to be economic.
New Zone Substation Tatapouri/ Whangara Note: this project is in response to Feeder issues (refer to Section 0 for the project drivers)	There is an 11kV link between the Kaiti substation (Dalton feeder) and the Tolaga Bay substation (Rototahi feeder). The distance between the two substations is >40km. There is also a tie with Patutahi Sub (Waimata Feeder) further along the feeder. With a load increase on these feeders, the voltage drop at the extremities of the feeders will likely reach the lower threshold limit. This voltage constraint will worsen when the feeders are used to provide a backup supply, so they are limited in their backup capability.	It is proposed to utilise the 50kV subtransmission line running alongside the 11kV line and install a 2.5 MVA zone substation at Whangara. This location is the tie point between the Rototahi, Dalton and Waimata feeders. The solution will also address the voltage constraints that will likely develop should load continue to be added to these feeders. Additionally, load from the Kaiti substation can be offloaded onto this new substation, easing the projected contingency constraint. **Budget: $2.1m** **Schedule: RY2031-RY2032**	• Do nothing (will have voltage constraints and load issues). • Reconductoring sections of the 11kV lines. This may help with voltage drop issues in some parts. However, significant length of lines must be reconducted to have any impact. Also, in some places, it will have minimal impact due to the distance of the feeders from the substations. This option is not economic compared to the proposed solution.

2023 constant $000.

10.6.2 Distribution network security and capacity enhancements

There is the potential to improve feeder security of supply through enhancements to the 11kV backup from adjacent feeders. This work supports asset management strategy #4.

Distribution security development options under consideration

Table 55 summarises the work in progress on enhancing 11kV feeder security. For these feeders, the final solution has not yet been determined. Several of these projects are expected to move onto the proposed list of projects before the publication of the 2024 or 2025 AMP.

Table 55: Distribution feeder security and capacity development options being considered

Feeder	Issue	Discussion on potential solutions
Hershell	No contingency backup. The feeder has no ties with neighbouring feeders	The feeder load is within the mobile generator capacity and is not projected to exceed this capacity within the forecast period.
Cedenco	Cedenco is an industrial consumer connected to the 'Cedenco' feeder on the Parkinson substation. They have indicated that future expansion is likely and are seeking an additional 2MW capacity. This load is expected to increase the demand beyond the cable capacity of the feeder.	Consideration is being given to installing switchgear on a neighbouring feeder that can supply this additional load. Although this is a good solution, a tactical disadvantage of this option is that half of the consumer's plant will be without power if either feeder trips. The advantage is that this option is considerably cheaper than the alternative. The alternative is to extend the Parkinson switchboard and connect an additional circuit breaker. This will allow the construction of a new dedicated underground cable from the substation to the Cedenco site.
Tikitiki and Awatere	Tikitiki and Awatere feeders provide the 11kV link between the Ruatoria and Te Araroa feeders. The feeders also provide the 11kV link for the generators at each substation. Recent load growth on the two feeders has increased the voltage drop to 10.5-10.6kV at the end of the feeders. Reconductoring of the line will be of minimal assistance.	Two options are being considered for these two feeders: • A 3ph voltage regulator could be installed at the feeder tie switch, which would help support operating voltages when a tie is needed. • A small substation could be built near the Tikitiki township using the 50kV subtransmission line, which runs parallel to the Tikitiki feeder. Presently, both options are considered uneconomical and non-urgent as no planning criteria triggers have been breached. If growth continues, one of these options will likely be required.
Dunstan and Waipaoa	The Dunstan and Waipaoa feeders supply a rapidly growing industrial area. Demand growth indicates that the original 95mm cable at the end of the Dunstan feeder will constrain the contingent capacity in the coming years. The 95mm cable loops into private property, back onto the feeder, and is roughly 200m long.	It is proposed that the 95mm cable running into private property be used as a spur line (using switchgear) and the remaining 80m of 95mm cable be upgraded to 185mm. Benefits of the project include: • Full contingent capacity in the event of a fault on either feeder • Futureproofing the feeders for additional load growth • Improvement in reliability.
Tahora and Matawai	The Tahora feeder (Ngatapa Sub) has an 11kV link to the Tahunga feeder (Pehiri Sub). However, due to the distance and feeder	An option would be extending the Tahora feeder 11kV line on Tahora Rd to join the 11kV line on the Matawai Feeder (Puha Sub). The distance is approx. 2.5 – 3km, depending on the line route.

Feeder	Issue	Discussion on potential solutions
	configuration, the Tahunga feeder can only provide partial backup for the Tahora feeder load.	This will enable the Matawai feeder to provide contingent backup supply for part of the Tahora feeder (which currently can't be provided by the Tahunga feeder), and the Tahora feeder can provide backup supply for part of the Matawai feeder load (which presently has no backup supply).

Proposed distribution security development projects

Table 56 summarises the proposed distribution security projects included in our expenditure forecasts.

Table 56: Proposed distribution feeder security projects

Feeder	Issue	Proposed solution	Alternatives considered
Frasertown and Raupunga	The Raupunga and Frasertown feeders are long (>40km) feeders originating at the Wairoa substation and looping around the rural townships on the south side of Wairoa. The voltages are constrained at the far end of the feeders where the tie switch between the two feeders is located. Any significant growth on these feeders is likely to require network development.	Refer to the Frasertown and Raupunga generators project in Table 64.	Refer to the Frasertown and Raupunga generators project in Table 64.
Rototahi and Dalton	There is an 11kV link between the Kaiti substation and the Tolaga Bay substation. The distance between the two substations is >40km. There is currently a voltage regulator located at Tatapouri, which supplies the consumers on the Kaiti side and is used to support the 11kV link to Tolaga Bay as a reference voltage for the diesel generator located at Tolaga Bay. The additional load on either of the two feeders will drop voltages along this line to the point where a reference for the generator cannot be made, and the voltages along the line will reach minimum operating limits. A tie also exists to the Waimata feeder (Patutahi Substation). However, this link is already at its limit and cannot provide additional support.	Refer to the New Zone Substation Tatapouri/ Whangara project in Table 54.	Refer to the New Zone Substation Tatapouri/ Whangara project in Table 54.

10.7 Gisborne Regional Subtransmission Development

The Gisborne regional subtransmission development program supports asset management strategy #6.

10.7.1 Issue

The entire Gisborne region is supplied by:

- The transmission grid to the Tuai GXP;
- The 110kV double circuit line from Tuai to Gisborne and a 2 x 60MVA 110/50kV substation located in Gisborne. These assets were acquired from Transpower in 2014;
- 5 x 1 MWe diesel generators owned and operated by Firstlight.

The firm[79] capacity available into the region is 55.5 MW. There are constraints on the "firm" of this capacity. The current 110kV Tuai to Gisborne double circuit line is N-1 electrically but not N-1 mechanically. Firstlight currently manages the lack of N-1 mechanical security through intensive risk management, but in 15-20 years, when replacing the line's conductors is required, many regional outages will be required to complete the reconductoring work. Hence, firm capacity from these lines is only available until around RY2040.

The current regional capacity is sufficient to meet current regional demand until RY2026. However, there is insufficient spare capacity to cater for any material industrial load growth (refer to Figure 97).

Figure 97: Gisborne region's forecast demand and capacity

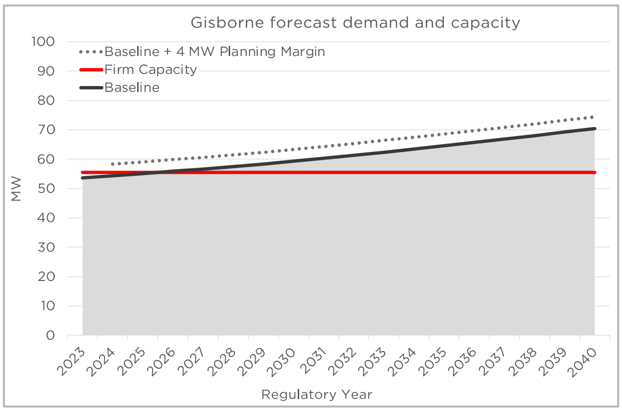
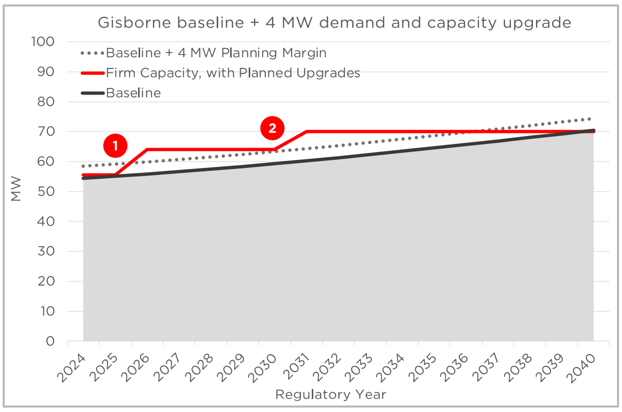


Figure 98: Gisborne region's forecast demand with planned capacity upgrades



10.7.2 Proposed network solution (to meet organic growth)

The recommended network solution to meet Gisborne's regional baseline load growth involves a series of two incremental projects (refer to Table 57 and Figure 98). We have pushed out the timing of the thermal upgrade as the capacitor upgrade can now deliver more capacity than initially thought (due to the upgrade to the existing capacitor banks).

[79] In this context, "firm" means at N-1-g security. N-1-g means the capacity with the largest network element out of service and the largest generator out of service.

Table 57: Proposed solution to meet organic growth requirements.

Stage	Solution Firm Capacity	Year required (to meet forecast MD)	Solution description
1	64 MW	End RY2026	• Install 2 x 6 MVAr 50kV capacitor banks (exact bank sizing to be confirmed at the detailed design stage) and remove existing 110kV MVAr capacitors • Replace the controls on the existing 12.5 MVAr capacity bank. **Budget: $470k** **Schedule: RY2026**
2	~70 MW	End RY2032	• Thermal upgrade of GIS-TUI 110kV lines to 75°C, which involves: o Clearing high points under the tower line; o Increasing the height of pi-pole structures; o Increasing the height of towers; o Tower strengthening, foundation strengthening, insulator replacement. • The total thermal upgrade cost is estimated at $14m, of which $4.4m has already been completed (leaving a total remaining budget of $9.6m). • There is an overlap between this work and other tower and pole renewal work. A total of $2.5m of line renewal work will no longer be required as the replacement of towers and pole structures is being completed as part of this project. **Budget: $9.6m (remaining)** **Schedule: RY2022-RY2032**

2023 constant $000.

The 2021 AMP included a second installation of capacitance in RY2034. This has been removed as the existing 12.5 MVAr bank is being retained. Further study is required before additional capacitance is included.

10.7.3 Potential network solution (to meet step-change growth and improve mechanical security)

The solution in Figure 98 and Table 57 increases the capacity but does not resolve the mechanical security risk associated with the double-circuit 110kV tower line. Hence, implementing the solution described in Table 57 requires that particular attention is paid to the 110kV tower line risk mitigation, and can only be considered to provide capacity to RY2035-RY2040 (a separate risk study has been undertaken and is discussed in the fleet plan, refer to Section 11).

Additional security and capacity enhancements (or alternatives) will be required in the mid to late 2030s (for commissioning by RY2040) to enable the conductor renewal on the existing GIS-TUI-A 110kV line.

The solution described in Table 57 only provides firm capacity to the early 2040s (assuming no step-change in industrial load growth). This work may need to be advanced should the industrial load increase materially or electrification of transport and residential/commercial heat occur faster than currently assumed. We are commencing work on this project early to provide the option to advance this work should load growth require it.

Table 58 presents the options currently being considered, and Figure 99 illustrates the potential impact on demand. These options are in an early concept, feasibility and costing phase. Consultation and discussion on the options have not yet commenced. Further work on alternatives is also being assessed, *including generation options to support reconductoring the existing GSI-TUI-A line.*

Figure 99: Gisborne region's forecast demand with planned and potential capacity upgrades

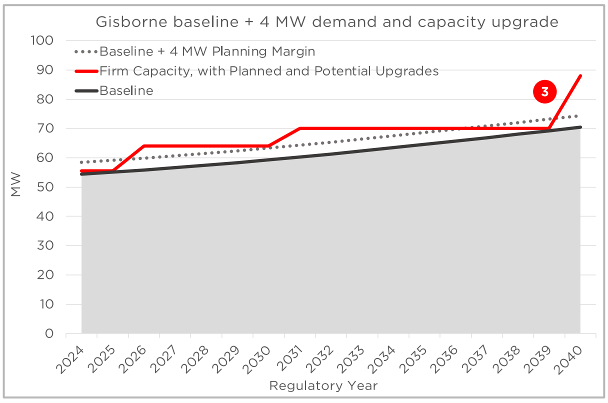


Table 58: Options to provide step-change capacity into Gisborne

Description of Option	Comments
Do nothing	Does not achieve the objectives
New 110kV line from Wairoa to Matawhero	This line would utilise the existing raid corridor. This option provides 88MW of firm capacity[80], which supports load growth to RY2054 and improves security (full n-1). The estimated cost is $81m.
Full reconductoring of the GIS-TUI line.	This provides 67 MW of firm capacity, which supports load growth to 2038. This option does not increase security and has some constructability issues to resolve. Further work on the options to support the reconductoring is required. The estimated cost is $44m.
New Frasertown to Patutahi 110kV line.	This provides 88 MW of firm capacity, which supports load growth to RY2054 and improves security (full n-1). This option offers firm capacity for growth for nearly the next three decades and improvements in security. The estimated cost is $83m.
New Frasertown to Gisborne 110 kV line.	This provides 88 MW of firm capacity, which supports load growth to RY2054 and improves security (full n-1). This option has significant land route issues. The cost is yet to be assessed.
New GIS-TUI 110kV line.	This provides 67 MW of firm capacity, which supports load growth to 2038 and improves security (full n-1). This option has significant land route issues. The cost is yet to be assessed.
Generation alternatives within the Gisborne region	This alternative is being considered as part of a further study.

2023 constant $000.

We expect to update progress in our 2024 or 2025 AMP.

80 With the existing GIS-TUI-A considered as a single line.

10.8 Use of Non-Network Solutions

10.8.1 Demand-side management (flexibility)

Hotwater ripple control

Firstlight uses traditional ripple control for demand-side management. The load control systems were initially designed to reduce domestic hotwater cylinder demand at peak times. Their use continues to reduce peak demand across the transmission, subtransmission and distribution systems.

Around 13,600 consumers in Gisborne and 2,000 in Wairoa have access to load control.

In the Gisborne region, the application of load control is inherent in the historical system demand. As such, its continued operation is assumed in the load forecasts presented in Section10. The contribution from load control on historical system demand is estimated to be 3.0MW on the Gisborne network and 0.6MW on the Wairoa network. This is well below the maximum available due to increased demand during the restoration of the hotwater load.

The maximum available demand reduction is approximately 13.9MW on the Gisborne network and 2.5MW on the Wairoa network.

Table 59: Ripple control estimated interruptible load by area

Region	Estimate of maximum interruptible load (kW)
East Coast (Ruatoria, Te Araroa and Tokomaru Bay)	1,800
Gisborne North (Kaiti and Tamarau)	5,500
Gisborne South (Mangapapa, Riverdale and Te Hapara)	6,600
Wairoa	2,500

Other demand management initiatives

Firstlight encourages (by way of removing any barriers to connections or upgrades) consumer-based demand-side management. Examples of two initiatives:

- Replacement of the compressor drives with variable speed drives on Eastland Group's cool store;
- The Mahia Sewage scheme (installed in 2013) uses small pumps on each installation to add diversity and avoid the peak loading often seen when large pumps are used.

Future demand initiatives targeting a shift in consumption from during the day to between 12:00 am and 4:00 am will have the most significant impact on demand. Load shifting is part of the pricing strategy (refer to pricing methodology and roadmap).

Upgrading of the ripple control system

Firstlight operates two ripple control plants in Wairoa (11kV) and Gisborne (50kV). The systems still control the streetlight circuits for the two regions. Health assessments of the existing plant have determined that the Makaraka plant (Gisborne region) is reaching end-of-life criteria and will need replacement.

Table 60: Proposed ripple control project projects

Project	Issue	Proposed solution	Alternatives considered
Replace ripple injection plants	The plant has reached its end-of-life and suffers regular failures. The plant is required for the ongoing ability to control	Installation of new Ripple plant in the Gisborne region. **Budget: $500k** **Schedule: RY2024-RY2025**	• Using the flexibility market. This market is not considered suitably developed.

Project	Issue	Proposed solution	Alternatives considered
	load. The plant is also needed for the Gisborne Street lighting	Note: This project is asset replacement and renewal expenditure as its primary driver is end-of-live replacement.	• An 11kV system was considered but had signal strength limitations

2023 constant $000.

10.8.2 Distribution generation

Firstlight is working with various distributed generation providers to facilitate the connection of medium and large-scale generation. Where these projects avoid the need to upgrade the network, we will consider paying the avoidable cost of distribution ("**ACOD**").

These projects are confidential between Firstlight and the distributed generation provider. Details of any developments will be included in future AMPs where the development is made public.

Developing a "statement of opportunity" to seek proposals from distributed generation providers is being considered where there are opportunities for non-network solutions to meet security or demand growth needs.

10.9 Resilience Strategy and associated Network Developments

10.9.1 Introduction

In the modern context, resilience means:[81]

- The capacity of the network to absorb a shock; recover from disruptions; adapt to changing conditions; and retain essentially the same function as it had before;
- Having the capacity to adapt to those shocks and rapidly recover, even if that means providing services in a new way.

In practice for EDBs, resilience means:

- Minimising the potential number of consumers interrupted during a major event (generally by way of risk reduction);
- Minimising the duration of the interruptions that occur during a major event (generally by way of readiness and response);
- Communicating with consumers and stakeholders so that they can be informed in their decision-making and so that restoration can be effectively coordinated and targeted;
- Recovering to the pre-event state.

This section outlines our initial view of our resilience strategy and the proposed projects to improve resilience. This section principally focuses on risk reduction (which drives network expenditure).

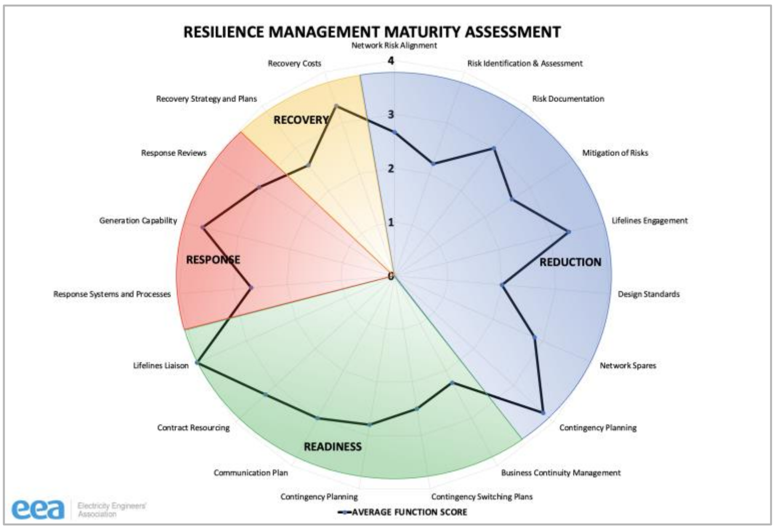
The details of our resilience strategy will be further expanded in the 2024 AMP to cover all aspects of resilience. The elements of the resilience strategy that drive network expenditure will remain in this section. The elements of the resilience strategy (including cyber security) that drive process improvements will be included in the AMP roadmap section.

10.9.2 Current RMMAT Assessment

We have completed an initial RMMAT assessment (refer to Figure 100). These weaknesses in risk identification and mitigation, design standards, contingency planning and response systems and processes have been considered in developing (and are addressed by) the resilience strategy.

[81] DPMC, "Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system", June 2023.

Figure 100: RMMAT Assessment



10.9.3 Cyclone-impacted areas

Cyclone Gabrielle damaged the entire Tairawhiti and Wairoa network and left some rural communities isolated due to road damage. Similar areas were affected by both cyclones, which tended to be caused by excessive water in the water catchment areas and land movement/slips.

The extreme weather resulted in major adverse environment, adverse weather, and vegetation outages. The roading network was severely impacted, which limited access and resulted in outages taking longer to restore.

In addition, power to the GXP was lost, affecting the whole district in cyclone Gabrielle, which delayed restoration for that period.

Table 61 shows the areas impacted by long-duration outages during RY2023 (this is our initial view, and further analysis is planned). These areas are a key focus for our improvement projects.

Table 61: Summary of communities impacted and the fundamental causes of the long-duration outages

Community/area	Cause of the long-duration outages
Te Arai	Multiple slips prevented access into the area. Eventually, when access was restored, a further slip caused a pole to fall into the river and could not access the new site. No ring feed was available, and we could not install diesel generators because of the configuration of connections.
Frasertown and Rangihua	We could not gain access at the start of the feeder or back feed as the ring feed had an existing fault. When access was restored, multiple faults were found that took considerable time to repair.
Matawai and Otoko	We could not gain access to the fault, which was located at the start of the feeder. Hence, a significant number of consumers could not be supplied as no backfeed was available.
Ruatoria	The initial fault could not be repaired due to access. The Ruatoria Diesel generator was started and restored power to most consumers, but an additional slip blocked access to the generator site, so it could not be refuelled.
Mata	Multiple trees through lines and slips at the start of the feeder prevented access. The alternative back feed had multiple faults, so the ring feed was unavailable.
Ruakituri	A single 11kV line supplies this area with difficult access and no backfeed supply. Support is generally provided using our mobile generator. However, due to roading access constraints, this is less viable.
Various feeders on the East Coast	Analysis is in progress on these communities

10.9.4 Cyclone impacts on network assets

We saw a number of faults and failures on the overhead network during cyclone Gabrielle.

During Cyclone Gabrielle, weather stations recorded wind gusts upwards of 140 km/h to 150 km/h. Higher wind speeds may have occurred due to local topographical influences.

The current design return period for a Level 3[82] overhead powerline (for a 50-year design life) for wind is 1:200. For Level 3, based on the current wind standard,[83] the base windspeed is 155 km/h for the central and upper North Island. Base windspeeds would be around 5 km/h lower for lines that don't require post-disaster function. Several wind speed modifiers are applied to derive the design wind speed for the site that could increase the design wind speed by up to 15% in the Gisborne and Wairoa region.

The recorded maximum gusts were close to base windspeeds applicable in the current overhead line designs in our region. Topographic factors influence the actual windspeed, so the true windspeed in some locations was very likely higher. Hence wind speeds were likely beyond the limits of older parts of the network that were designed to older (and lower) pre-2000 standards.[84]

10.9.5 Network resilience improvement strategy

In so far as the network is concerned, our resilience strategy comprises three themes:

- Actions that reduce the risk (i.e., Identifying hazards and mitigating vulnerabilities) to reduce the number of consumers impacts;
- Actions to restore consumers more quickly;
- Actions to address other weaknesses in our RMMAT assessment.

The enhancement of our resilience strategy is ongoing. However, to date, the new initiative comprises the eight actions shown in Table 1 below. The resilience strategy combines some existing workstreams and commences new work to understand better wind, flooding and geotechnical vulnerabilities that have become more acute due to climate change.

Table 62: Resilience strategy

Initiative	Description
10. Improve network resilience	Improve the resilience of the network to adverse weather events through: • Assessing wind, flooding and geotechnical hazards and implementing mitigation plans where appropriate (consistent with climate change); • Assess the worst-performing feeders to determine if there are improvement opportunities available; • Assessing the risk posed by pre-2000 overhead lines and implementing mitigation plans where appropriate; • Extend the accelerated pole replacement program to remove additional pre-2000 poles; • Enhancing our contingency plans, mutual aid plans and spares holdings; • Enhancing our SCADA and OMS; • Enhancing vegetation management activities concerning key feeders and the out-of-zone trees (see asset management strategy #2);

82 The highest standard where post disaster function is required.
83 AS/NZS 1170.2 (wind action).
84 In 2000 the design standards changed and were based on modern limit state designs.

Initiative	Description
	• Increasing distribution network automation and security enhancements, particularly the opportunities to enhance generation use (see asset management strategy #4).

Note: Cyber security forms an important part of our overall business resilience strategy. This is covered separately in Section 9 [x].

10.9.6 Assessing wind, flooding and geotechnical hazards and implementing mitigation plans

This action is in the scoping phase. The outcomes of this work will be included in the 2024 or 2025 AMP.

10.9.7 Preliminary view on actions to improve worst-performing feeders

Table 63 summarises our preliminary view on actions to improve resilience for the communities and areas most impacted by the recent cyclones. These are our initial actions to address the worst-performing feeders. Several of these initiatives have yet to undergo economic assessment and consumer consultation. We expect additional projects will be included in our 2024 and 2025 AMPs.

Table 63: Preliminary view on actions to improve resilience

Community/ area	Description of project/actions (i.e., strategies) being considered to improve resilience	Alternatives considered	Financial impact and timing
Matawai	Investigation alternative ring feeds from Ngatapa Sub, either from the Totangi or Tahora Feeder.	Installing a medium-sized diesel generator based at Matawai Township.	TBA
Mata	Reinstate Ihungia ring feed, which has been out of service due to multiple tree faults and land movement issues.	Connecting the Tauwhareparae Fernside Link with Mata Road	Reinstatement of ring feed completed in August 2023
Mata	Convert the remote switches to sectionalisers.	No other option was considered	Prioritised as part of the existing automation program
Frasertown	Install two diesel generators at strategic places on the Raupunga and Frasertown feeders.	No other option was considered	Refer to the Frasertown and Raupunga generators in Table 64.
Te Arai	Work with Gisborne District Council regarding better roading infrastructure, as an existing ring feed could not be accessed.	No other option was considered	There is no Budget Impact; consultation is underway
Ruatoria	Source diesel supply from external contractors that are near the diesel generators. Install FNL trailer Deisel tanks at the site to increase capacity.	No other option was considered	Build relationships with multiple Diesel suppliers. FNL already have Mobile diesel tankers.
Ruakituri	Installation of generator	No other option was considered	Refer to the Ruakituri generator in Table 64.

10.9.8 Assessing the risk posed by pre-2000 overhead lines and implementing mitigation plans where appropriate

This action is in the scoping phase. The outcomes of this work will be included in the 2024 or 2025 AMP. This risk has influenced the acceleration of the pole replacement program.

10.9.9 Extend the accelerated pole replacement program to remove additional pre-2000 poles

This action is being progressed. Refer to the wood pole fleet plan in Section 11.

10.9.10 Enhancing our contingency plans, mutual aid plans and spare holdings

This action is in the scoping phase. The outcomes of this work will be included in the 2024 or 2025 AMP.

10.9.11 Enhancing our SCADA and OMS

This action is being progressed. We discuss this project in more detail in the AMP roadmap (refer to Section 9.) Refer to Table 64.

10.9.12 Enhancing vegetation management activities concerning key feeders and out-of-zone trees

This action overlaps with asset management strategy #2 and is discussed in the vegetation management section (refer to Section 11.23).

10.9.13 Increasing distribution network automation and security enhancements, particularly the opportunities to enhance generation use

This action overlaps with asset management strategy #4. We have outlined our view of resilience enhancement projects (refer to Section 10.9.14). Other security and automation projects outlined in Sections 10.6.1, 0, and 10.10 support this action.

10.9.14 Proposed resilience enhancement projects

We have defined an initial list of resilience improvement projects (refer to Table 64). These projects address a number of the worst-performing feeders. We expect the project list will increase in the 2024 and 2025 AMPs as work on the various actions progresses.

Table 64: Proposed Resilience Development Projects

Project	Issue	Proposed solution	Alternatives considered
Tolaga Bay second transformer	Tolaga Bay substation has a 1MVA diesel generator for a contingency backup supply. The generator is mainly used to provide backup supply when there is an outage on the 50kV supply line to the coast. With the Gis-Toko 110kV line now operating at 50kV, an alternate supply line to the coast is now available, improving the security of supply for the coast. The generator is reaching end-of-life and will need to be replaced within the forecast period.	A second transformer is proposed to be installed at the Tolaga Bay substation to provide N-1 security (an improvement from C3 to B security). This will make the generator at the site redundant. **Budget: $1.57m** **Schedule: RY2032**	• To keep the same security of supply level, the generator will have to be replaced before reaching end-of-life. Also, there will be costs associated with maintaining the existing generator until a new generator unit is bought and in service. So, the proposed solution is favoured over the continued use of the generator, considering the maintenance and running costs.
Frasertown and Raupunga generators	The Raupunga and Frasertown feeders are long (>40km) with poor reliability due to the absence of any material backup supply. Consumers can experience lengthy outages on these feeders.	Install new generator sets in Raupunga and Frasertown feeders to support security (and voltage; refer to Table 56). Installing two generators at strategic places can provide backup supply during unplanned and planned outages on the feeders and	• Do Nothing (will have the same contingent capacity issues and reliability issues for the feeders) • New substation near Arkdeen, which is the area up to which the Raupunga feeder can provide a backup supply on the Frasertown feeder.

Project	Issue	Proposed solution	Alternatives considered
		provide backup for the other feeder in some circumstances. This will improve the reliability of these two feeders and reduce unplanned SAIDI & SAIFI for these feeders. **Budget: $1.05m (each)** **Schedule: RY2025 & RY2027**	However, it is considered uneconomical at this stage for the benefits gained compared to the proposed solution • Consumer-led solutions (i.e. behind the meter generation). This is not considered viable, given the number of consumers involved and the likely duration of outages.
Ruakituri generator	A single 11kV line from the Tuai substation supplies this area. This line is remote (off-road) with no backfeed possibilities.	Install a new generator near the community hub and school. A generator in this location will provide unplanned outage support for the area and supply Tuai village when planned outages on the substation are required. **Budget: $1.05m** **Schedule: RY2029**	• Consumer-led solutions (i.e. behind the meter generation). This is not considered viable, given the number of consumers involved and the likely duration of outages.
100kVA Trailer Generator	Some unplanned outages have significant restoration times (either due to the extent of the damage or due to access, resource or other constraints). Using portable generators can restore supply while permanent repairs are made.	Purchase a 100kVA portable generator that can be mobilised to reduce the impact of unplanned interruptions. The generator can also be used to minimise the impact of planned interruptions on radial feeders. **Budget: $65k** **Schedule: FY2024**	• Do nothing and leave consumers without supply outside of our service level period. • There were no other options to provide a cost-effective solution to supply consumers in an affected area.
350kVA container generator	Some unplanned outages have significant restoration times (either due to the extent of the damage or due to access, resource or other constraints). Using portable generators can restore supply while permanent repairs are made.	Purchase a 100kVA portable generator that can be mobilised to reduce the impact of unplanned interruptions. The generator can also be used to minimise the impact of planned interruptions on radial feeders. **Budget: $90k** **Schedule: FY2024**	• As above
1.0 MVAe spare generator	A spare generator will improve the resilience of the existing generator fleet and assist with the planned refurbishments.	A new 1.0 MVAe unit has been purchased and requires the control units to be modified to enable	• The project is in progress

Project	Issue	Proposed solution	Alternatives considered
	The existing 1.0 MVAe generator fleet is operating reliably, but the risk of failures is increasing due to the presence of end-of-life drivers. The existing 1.0 MVAe generator fleet is due for refurbishment. A spare generator is required to replace the existing generators while they are removed from the site for refurbishment.	changeover with the existing units. **Budget: $minimal remaining** **Schedule: FY2024**	
SCADA and OMS upgrade	Refer to AMP Roadmap, Section [9]. Our current SCADA system does not have functionality for outage manage and switch order management. It is a legacy system and lacks functionality to enable Firstlight to manage outages in a major event. It is currently a constraint for managing the restoration of supply in a major event.	Upgrade the existing SCADA system and develop an OMS. Currently there are two systems extensively used and supported in NZ. These are GE PowerON and OSI Monarch, Electra and Spectra. We have yet to assess which system is the best fit for Firstlight and its customers.	We are currently considering whether the system is implemented in house or whether the provision of SCADA, OMS, and control room services are outsourced or undertaken by way of a joint control room.

2023 constant $000.

10.9.15 Consultation with consumers

We intend to undertake consumer consultation with consumers concerning the resilience projects. This will assess consumer's expectations and their willingness to pay. A consultation plan is yet to be developed.

Whilst the costs associated with the resilience actions are not directly attributable to the communities, we believe consulting with consumers before proceeding with the projects is necessary. This will test whether those communities believe the solutions will assist and their appetite for the cost/benefit trade-off.

10.10 Network Developments to Improve Reliability

10.10.1 Introduction

In the 2021 AMP, the reliability improvements developments comprised three programs: distribution automation, early detection of earth-fault hazards through SCADA monitoring of earth fault pick-up (pre-trip), and a review of the protection discrimination. The latter two programs have been completed and are operating successfully.

Of the projects identified in the 2021 AMP, work was completed on the Inland and Matawai feeders. The Te Karaka feeder project has been replaced by automation of the adjacent Kanakanaia feeder. No additional automation will be installed on the Te Arai feeder as no suitable location for protection discrimination could be found.

10.10.2 Distribution automation

Installation of reclosers and sectionalisers can minimise the impact of outages to consumers on the network. Analysis of faults has identified sites that would benefit from an automated protection system.

Firstlight has developed a strategy which comprises two components:

- Installation of reclosers and sectionalisers. This will help sectionalise and identify the fault area quicker, improving response time;
- Automation of remote systems to reduce response times to restore supply. The strategy is to target sites with travel times over one hour from Gisborne.

Distribution automation program

Table 65 summarises the forecast expenditure on the distribution automation program and the automation of existing switchgear. The distribution automation forecasts equate to two new reclosers, sectionalisers or switches each year.

Table 65: Distribution Automation Program

Expenditure category	RY2024	RY2025	RY2026	RY2027	RY2028
Distribution automation program	42	42	42	42	42
Automation of existing switchgear	-	35	35	-	36

2023 constant $000.

Proposed distribution automation development projects

Table 66 summarises the proposed distribution automation projects included in our expenditure forecasts. These projects cover RY2024 and RY2025. Specific projects for later years will be included in subsequent AMPs.

Table 66: Proposed Distribution Automation Projects

Feeder	Issue	Proposed solution	Alternatives considered
Hicks Bay	The feeder has not been sectionalised sufficiently, contributing to an annual average of 11 SAIDI minutes. The 3.5-hour travel time from the Gisborne depot is also contributing to SAIDI.	This project involves installing two new sectionalizers at the Waikura Valley and Lottin Point tee-offs. This will enable automated protection from these spur lines and be within the protection discrimination limits for the feeder. **Budget: $42k** **Schedule: RY2024**	• No viable alternatives were identified. This project is part of a range of measures to improve reliability. • Line inspections and replacements have been prioritised for this area
Waimata	The Waimata feeder previously did not include the Waimata Valley, which was on the Bushmere feeder. Since the shift, the average annual SAIDI on the Waimata feeder has more than tripled.	This feeder was reviewed to determine the feasibility of installing a remote switch to isolate the section that connects to the Dalton feeder. Due to the new fault-finding procedure, it was suggested that a sectionaliser be installed at E1237 instead. This would clear faults along the area of unreliability and keep 43 consumer supplied if impacted by outages. **Budget: $21k** **Schedule: RY2025**	• Do nothing (not viable due to high SAIDI). • Shift existing circuit breakers to optimise location (will minimise coverage area, and the cost to carry out is equal to the cost of new install)
Kanakanaia	The Te Karaka feeder project was reviewed, and it was found that the Kanakanaia feeder, which also supplies the Te Karaka township, was impacted more than the Te Karaka feeder (50 SAIDI over the last four years).	There is no automated protection on the Kanakanaia feeder. Installing a circuit breaker past the Kanakanaia Voltage Regulator would clear faults near the end of the line and protect the township from outages. This will keep 144 consumers supplied.	• Do nothing (not viable due to high SAIDI). • No viable alternatives were identified

Feeder	Issue	Proposed solution	Alternatives considered
		Budget: $21k **Schedule: RY2025**	

10.10.3 Projection upgrades to improve reliability

Table 67 summarises the planned protection upgrades to improve reliability.

Table 67: Protection Upgrades

Site	Issue	Proposed solution	Alternatives considered
50kV ring circuit around Gisborne	The 50kV circuit supplying the Kaiti, Port and Carnarvon substations operates as an open loop. In the event of an outage, switching is required to restore supply.	Installation of a unit protection scheme on the circuit will improve reliability. It will avoid the loss of supply in the event of an outage of any interconnecting lines. The first phase of this project is to install a high-speed communication circuit between Gisborne and Kaiti substations. **Budget: $64k (first stage)** **Schedule: RY2026**	• Do nothing. This does not meet the objective of improving reliability.
Installation of reclosing on the 50kV coast subtransmission feeder and 33kV line to Mahia	There is presently no reclosing on the rural and radial subtransmission circuits. Line patrols are required before re-livening. Some faults on this line are transient and could be cleared through auto-reclosing.	Assess and install line reclosing on the 50kV coast and 33kV Mahia subtransmission feeders. A safety assessment is required as part of this project. **Budget: $236k** **Schedule: RY2025 to RY2028**	• Do nothing. This does not meet the objective of improving reliability.

10.11 Network Developments to meet other planning criteria.

Other planning criteria triggers have been considered. There are no material projects identified in this AMP.

The Grey St and Cameron Rd projects identified in the 2021 AMP have been completed.

10.12 Supporting the Energy Transformation

10.12.1 Introduction

Reducing emissions through electrification and increasing renewable generation are critical for New Zealand to achieve net-zero 2050. In particular, electrification of transport and heat (both process and general), expanding the use of distributed energy resources (**DERs**) and increasing the availability and use of flexibility are central pillars to achieving decarbonisation.

There is general recognition of EDBs' importance in the energy supply chain. EDBs form the critical link between consumers and energy markets and can enable greater participation by consumers in the decarbonisation efforts (or constrain involvement if they are ill-prepared).

Enabling decarbonisation through electrification requires that EDBs:

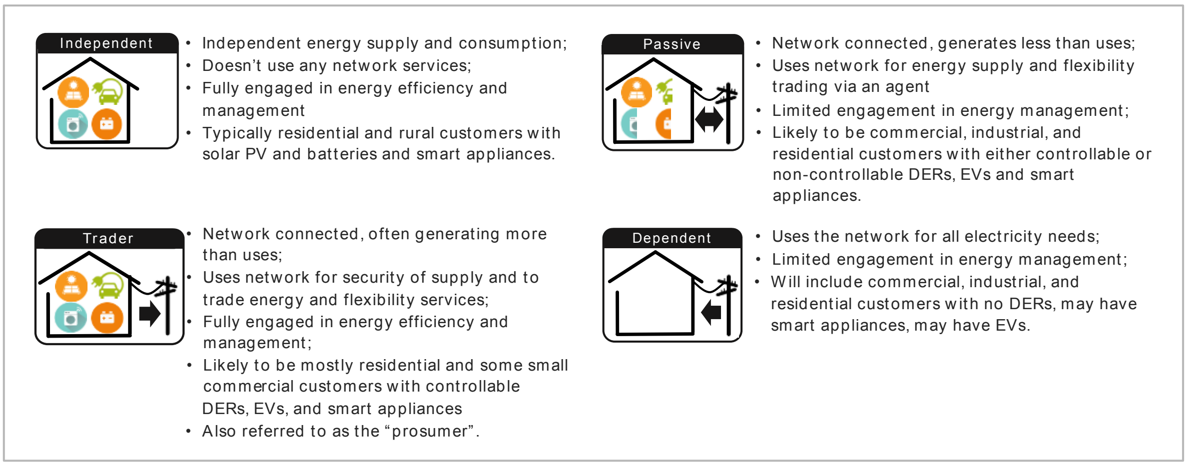
- Have the capability and network capacity to allow consumers to increase their use of electricity to replace fossil fuels;
- Can connect and integrate DERs to the network and allow the owners of DERs to participate in energy markets (including flexibility markets).

The collective elements of transition are called the “energy transformation” in this AMP.

10.12.2 Consumers are at the centre of the energy transformation

Consumers are at the centre of any operating model. Much has been written about the evolution of energy consumers. We have distilled this work into four types of consumers. The difference between them relates to the adoption of technology and engagement with energy markets (except the independent consumer, who, as the name suggests, operates independently of the energy market).

Figure 101: Future electricity consumers



10.12.3 Role of Firstlight in the Energy Transformation

As the energy transformation evolves, Firstlight will provide the key link between consumer's DERs and energy markets. It will continue providing energy security to consumers who continue to depend on grid-supplied electricity. However, the energy transformation will require Firstlight to adopt a new business model that will:

- Develop the network to allow all consumers to adopt (and fully benefit from) new energy technology such as EVs and DERs;
- Utilise flexibility (where practical and economic) to minimise capital expenditure on network upgrades.

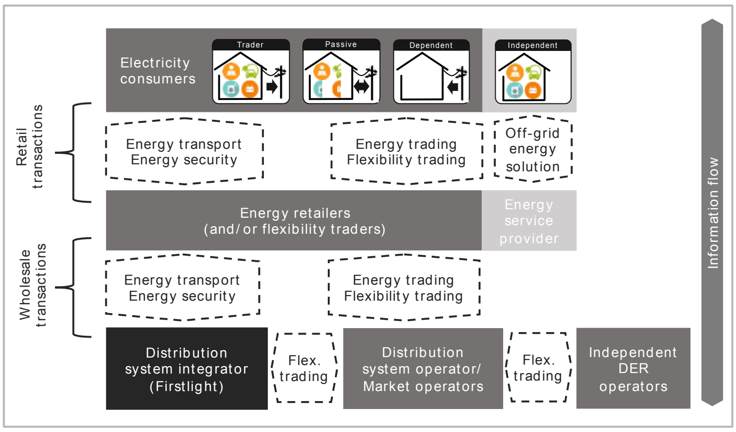
Figure 102 is our view of the operating model (which is consistent with the general industry view and, importantly, is consistent with the EA’s views in their recent regulatory settings paper[85]).

There is a reasonable consensus that Firstlight needs to evolve into a distribution system integrator. A distribution system integrator:

- Operates the distribution network to connect consumers (with and without DERs) to energy and related markets;
- Develops the distribution network to integrate DERs, support bidirectional power flow and enable the use of flexibility;
- Invests in the systems required to support open access to the distribution network for a wide range of consumers and DERs.

[85] https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/

Figure 102: Future-state model for Firstlight



The key transactions in the model are:

- Consumers (particularly those with DERs) purchase distribution services via their energy retailer. These services are electricity transport services and energy security services. Firstlight provides these services at a wholesale level to energy retailers who on-sell them to consumers;
- Consumers purchase electricity or sell their excess electricity (those with DERs) via their energy retailer;
- Consumers "bid" their interruptible demand (or energy reserves), and EDBs offer to purchase the interruptible demand (or energy reserves) via markets. It is likely that this "bidding" is procured annually rather than in real time;
- EDBs offer to purchase interruptible demand (or energy reserves) at a network level, and independent DER providers bid to supply these services via markets.

10.12.4 Potential impacts of the energy transformation

Based on Transpower's Whakamana I te mauri Hiko report, DERs and EVs will affect the traditional load profile and the load flows across the network. Assessment of the potential impacts on the network has indicated that (in general):

DERs impact

The increasing use of DERs will result in bidirectional power flows on some parts of the LV and 11kV systems.[86] The implications of the increase in DER penetration will be location-specific. However, modelling suggests that in "typical" urban areas, the issues involve:

- Reverse power flows causing over-voltage on parts of the LV system (this may occur as solar DER penetration rates increase above 20%);
- Reverse power flows causing overloaded conductors/cables on parts of the LV system (this may happen when DER penetration rates increase above 20%);
- Reverse power flows on some distribution transformers as DER penetration levels increase above 40%.

These issues could result in the network operating outside of statutory voltage limits (creating liability issues) and could create protection coordination issues (creating safety issues).

We forecast DER penetration to reach 9% for Gisborne by 2033 and 16% by 2040 (Wairoa is forecast to be materially lower). Hence, no material impact over the planning period is expected. However,

[86] As an example, there are suburbs in Australia where penetration rates are above 50%, whereas national penetration rates are below 20%. Refer KPMG, "Residential PV, Consumer Experiences and Future Developments, A Report for Energy Consumers Australia", 2016.

the network may experience modest issues in the 10-20-year horizon (noting that more specific modelling is needed to confirm this).

The research indicates that the impact on business districts and rural areas will be minimal due to the higher network capacity of business district networks and the lower consumer density of rural networks.[87]

From an operational perspective, network isolation procedures will need to be modified to ensure no unintended stranding of DERs that could pose a risk to work crews and the public. There is also the risk of out-of-phase reclosing (post-fault), transient over-voltage, and increased restoration times after faults.

EV Impact

The impact on the LV system from EV charging will be location-specific. Typical urban LV networks should be able to cope with EV charging for penetration rates up to 40%, provided:[88] [89]

- Consumer-level load control is used (to manage charging at peak times);
- “In-line” charging is used (as opposed to fast charging).[90]

Our forecast is for the EV penetration rate to reach 36% for Gisborne by 2033. Lower rates are expected for Wairoa, and there should be minimal impact over this planning period. However, penetration rates are expected to accelerate in the 10-20 year horizon, causing issues to emerge.

In the short to medium term, LV networks in CBD areas are unlikely to experience systemic issues due to EV charging. They should be able to handle the installation of fast charging stations. However, some localised upgrades may be required where the new high-capacity fast chargers are installed.

Analysis of the distribution network suggests that it will generally be able to cater for demand growth (including the expected EV charging) over the planning period (refer to Section 10.6.2). However, issues may arise if the charging occurs at peak times (and further modelling is required to confirm this).

10.12.5 Understanding the uncertainty and impact of flexibility

The discussion in Section 10.12.4 was based on DERs supporting a reduction in peak demand and EV charging avoiding peak demand. However, this may not occur. We have undertaken some initial analysis, which indicates that an uncontrolled EV and DER usage could increase peak demand by 8 MW (11%) in Gisborne and 1 MW (5%) in Wairoa by RY2033 (refer to Figure 103 and Figure 104). By 2040, these increases are 16 MW (21%) and 2 MW (11%) for Gisborne and Wairoa. Our analysis does not include the loss of hotwaterhot water demand response, which would increase demand by 3 MW in Gisborne and 0.6 MW in Wairoa.

This higher demand will drive higher network development capex (which has not yet been assessed).

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87 Watson et al, “Impact of solar photovoltaics on the low-voltage distribution network in New Zealand, IET Generation, Transmission and Distribution, 2015.

88 Watson et al, “Impact of Electric Vehicle Chargers on a Low Voltage Distribution System”, EEA Conference, 2015. The constraining issue is under-voltage.

89 Our view is that Eastland’s LV system is likely to be “typical” (and is comparable to the research cited) as no systemic loading or voltage issues are identified in this AMP. However, we note that it is inherently difficult to determine LV voltage and load limits without data on LV circuits, hence obtaining this information is a key response action.

90 In-line chargers are the standard chargers fitted to EVs and are not “fast charging”. Fast charging can draw six times the current of an in-line charger. Some new fast chargers have even larger current ratings.

Figure 103: Gisborne region's forecast demand controlled vs. uncontrolled demand

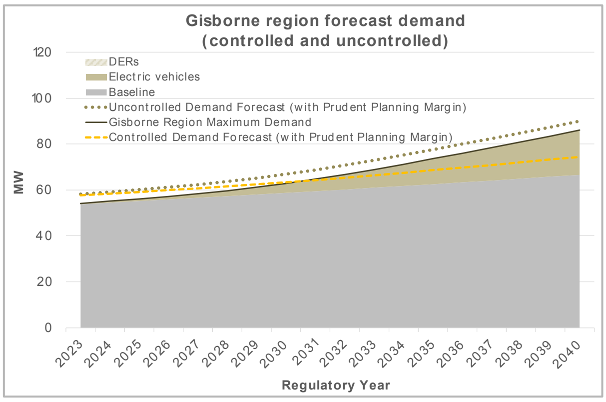
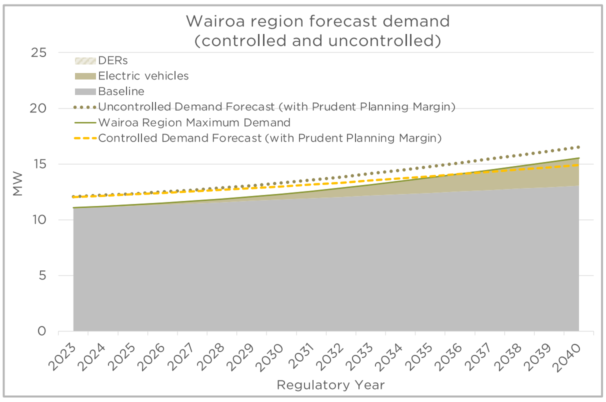


Figure 104: Wairoa region's forecast demand controlled vs. uncontrolled demand



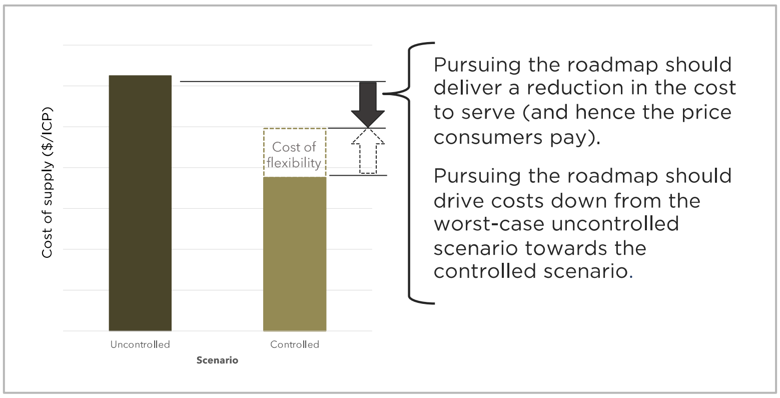
10.12.6 Development of an energy transformation roadmap

We are in the process of adopting an energy transformation roadmap. The primary objective of the roadmap is to deliver the least-cost network that will:

- Ensure Firstlight has the network capability to allow consumers to connect and increase their use of electricity to replace fossil fuels;
- Ensure Firstlight can connect and integrate DERs to the network and allow the owners of DERs to participate in energy markets (including flexibility markets);
- Guide the development of the distribution network to integrate DERs and support bidirectional power flow, which includes having appropriate hosting capacity to cater for growth in DERs;
- Guide the development of the systems and processes required to support open access to the distribution network for a wide range of consumers and DERs.

Our current view is that the least-cost network will be where EV and DER demand response assists in reducing peak demand (subject to the cost of flexibility associated with the EV and DER demand response).

Figure 105: Illustrative roadmap objective



Note: A portion of the cost of flexibility services will flow back to the consumers who provide these services. Hence, there should be more significant consumer benefit in the controlled scenario.

At this point, it is difficult to determine whether a controlled or uncontrolled peak demand will prevail. Hence, over the next decade, it is important that we define network and non-network investments that have low investment stranding risk. This means that early-stage projects should be relevant to both controlled and uncontrolled scenarios.

We will publish more on our energy transformation roadmap in our 2024 AMP.

10.12.7 Near-term actions to advance the energy transformation roadmap

As already stated, the network will generally be able to cope with the expected EV and DER uptake over the next ten years. There may need to be some localised capacity upgrades, but these are not likely to be material, and we believe that these can be managed within our current five-year forecasts (subject to further modelling). Hence, there is time to prepare for the impacts of the energy transformation and to prepare a future-state business model.

Whilst we are still finalising the adoption of our energy transformation roadmap, we have identified some near-term actions (refer to Table 68). These are broadly consistent with the actions we included in the 2021 AMP, albeit some dates have been pushed out. We expect the actions to evolve and become more defined over the subsequent two iterations of the AMP.

Table 68: Near-term actions to the energy transformation roadmap

Phase	Activity	Indicative timing
Investigation and monitoring	• We will be monitoring how the rollout progresses as smart meters are necessary to allow for DERs • Presently, 70% of households have a smart meter (but we only received data from 57%).	• In progress by others
	• Firstlight has implemented a distribution solar trial, which will follow some typical installations and capture data in real-time that can be extrapolated to determine the future impact on the electricity assets	• In progress
	• Monitor the evolution of distribution business models and changes in technology	• In progress
ToU pricing to encourage demand in off-peak time	• Eastland Network applies Time of Use (**TOU**) tariffs to all consumers with a reliably communicating smart meter. These TOU tariffs enable consumers to manage their loads more effectively and use a cheaper off-peak tariff.	• Complete
Constraint and solution modelling	Undertake planning and modelling to ensure that the network is not a constraint on the uptake of DERs and EVs. The modelling shall assess the impact of the energy transformation scenarios and solutions across the following: • Capacity; • Voltage; • Hosting capacity; • Harmonics. We will include the results of this work in our 2024 and 2025 AMP.	• RY2024 to RY2025
Enhance network monitoring	• Install LV monitoring to understand the real-time demand on the LV system. • Roll-out dependant option analysis vs. smart meter data	• Trial commencing in RY2024 to RY2025 • System rollout TBA
	• Assess whether LV monitoring can be achieved by way of smart meter data	• RY2024 to RY2025
	• Implement sophisticated real-time SCADA and ADMS (including at a low voltage circuit level) • Interface to flexibility markets (as they evolve)	• System rollout in RY2028+ (this will follow the OMS rollout)

Phase	Activity	Indicative timing
Enhance connection standards to reduce impacts	• To develop connection standards that reduce the impact of the transformation on the network whilst not adversely impacting the benefits to consumers.	• RY2025 to RY2026
Enhance operating procedures	• Implement more sophisticated outage management systems and adopt network isolation and live line practices to eliminate the risk of stranded DER operation.	• System rollout in RY2025 to RY2027

10.12.8 What this could mean for opex and capex over the long term

We will define the opex and capex implications of responding to the energy transformation in our 2024 and 2025 AMPs.

10.13 Network Development Expenditure Forecasts

Table 69 summarises the expenditure included in this section.

Table 69: Network Development Expenditure Forecasts

Projects	RY2024	RY2025	RY2026	RY2027	RY2028
Asset Relocations	51	51	51	51	51
Consumer connection					
Commercial	82	58	58	58	59
Residential	59	58	59	61	62
Quality of supply					
Generators	155	1,044	-	1,042	-
Automation and protection projects	42	155	219	120	77
SCADA and OMS Development	6	532	1,051	1,053	10
System Growth					
Distribution and LV cables	227	250	250	250	251
Distribution and LV Lines	352	398	397	397	398
Subtransmission	539	759	1241	3207	3216
Distribution substations and Transformers	157	219	219	219	219
Zone substations	-	157	520	104	523
TotalTotal	**1,670**	**3,680**	**4,001**	**6,562**	**4,866**

Note_Constant ($000's)

11. Asset Lifecycle Plans (Network Maintenace and Renewal)

This section describes how Firstlight manages the lifecycle of its key network assets

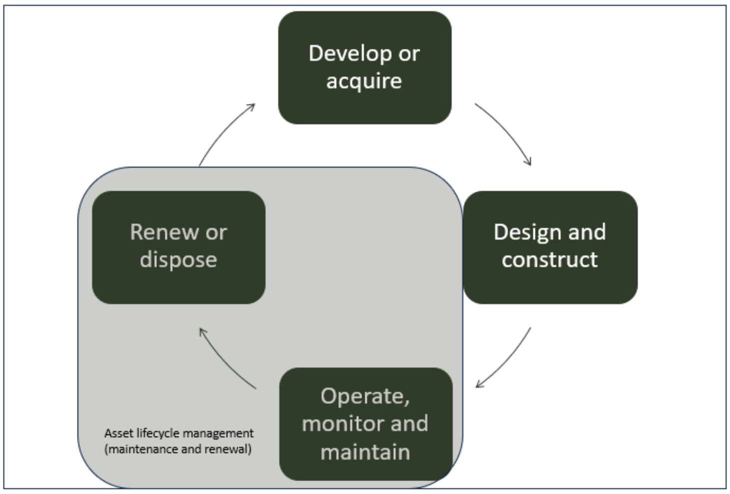
11.1 Introduction

This section identifies and discusses the factors that contribute to the *operate, monitor and maintain* and *renew or dispose* phases of Firstlight's assets.[91] In this section, we cover:

- The approach to assessing asset health;
- The approach to assessing asset criticality;
- Detailed fleet plans for our material asset classes;
- High-level fleet plans for other asset classes;
- Our vegetation management plan.

Individual asset fleet plans have been developed for the major asset types on the network and identify the issues, strategies, and operational support Firstlight employs to maintain assets over their entire life

Figure 106: Phases of the asset lifecycle



For this AMP, the focus is on the following key asset fleets:

- Structures (wood and concrete);
- Structures (steel);
- Conductor/lines;
- Power transformers;
- Substation switchgear;
- Ground-mounted transformers;
- Ground-mounted switchgear;
- Pole-mounted transformers;

[91] A description of the phases of the asset lifecycle are provided in Section 3.

- Pole-mounted switchgear.

The above asset fleets represent over 90% of the total value of the network (in RAB terms). A summary of any key issues, risks, projects, and expenditure forecasts is provided for other asset classes.

11.2 Asset Fleet Plans

We have developed fleet plans for each material asset class. These fleet plans include:

- An overview of the fleet;
- The strategy for managing the fleet;
- How the asset fleet is operated, monitored and maintained;
- How renewal decisions are made on the fleet;
- Fleet performance and risk;
- Fleet population and age;
- Fleet asset health and forecast maintenance and renewal requirements;
- Forecast expenditure on the fleet.

Our first fleet plans were included in the 2021 AMP, and the wood pole fleet plan was updated in the 2022 AMP. In this AMP, the fleet plans include the results of our condition inspections and testing completed over the past two years. They also include changes to fleet risks.

11.3 Approach to Assessing Asset Health

11.3.1 A change in approach from age-based to condition-based asset health assessments

The principal asset lifecycle strategy is to mitigate the risks posed by ageing or poor-condition assets on the network. This typically involves life extension maintenance or replacement of H1 and H2 assets before end-of-life failure.

We adopted the DNO Asset Health Methodology in 2021, which required new asset inspection standards to be created and new inspections to be undertaken. To fast-track the condition monitoring, an ambitious target of three years was set to complete the condition monitoring of material assets. Several new inspectors were added to the team to enable the completion of more inspections. An update on our progress vs. the inspection plan is provided in Section 6.

11.3.2 DNO Methodology to Determine Asset Health

The DNO common network asset indices methodology ("**DNO Methodology**") is a common framework of definitions, principles and calculation methodologies for assessing and forecasting asset health and asset risk. The DNO Methodology has been adopted by all distribution network operators across Great Britain and is commonly used by other EDBs in New Zealand.

Under the DNO Methodology, asset health is a measure of the condition of an asset and the proximity to the end of its useful life. The DNO Methodology includes a common methodology for the calculation of asset health for individual assets, which includes:

- The current asset health is informed by the observed and measured condition and
- Future asset health, using assumptions regarding the likely future deterioration in asset health.

To account for future deterioration, the DNO Methodology includes some age-based elements within the calculation of asset health.

As the health of an asset deteriorates (i.e. its condition worsens), the likelihood that it will fail increases. The DNO Methodology relates asset health to the associated probability of condition-based failure (the probability of failure or **PoF**). The DNO Methodology specifies the exact relationship between the asset health score and the PoF for each asset class. Therefore, under the DNO Methodology, the asset health can equally be expressed in terms of the PoF.

Adopting the DNO asset indices methodology has several benefits:

- Data-driven decisions: the DNO asset indices methodology relies on data analytics, ensuring the decisions are based on evidence;
- Proactive maintenance: it facilitates proactive monitoring of network assets, allowing for early detection of issues and reducing the risk of unplanned outages;
- Cost efficiency: Maintenance or renewal of assets is based on asset health, meaning resources are allocated more appropriately;
- Reliability: Improving asset health management reduces unplanned outages, benefiting customers.

There are limitations with the DNO Methodology in that it does not cover the asset classes that are used in the Information Disclosure Schedule 12a reporting. For the asset classes not available within the DNO Methodology, Firstlight will continue with age-based renewal forecasting applied consistent with the EEA asset health indicators approach.

11.3.3 Asset Health Indicators

The DNO Methodology reports asset health in a format of 0.5 -10, where 0.5 indicates an asset is "as new", and 10 indicates that asset replacement is required. The DNO asset health score is translated to the H1-H5 standard NZ reporting format as follows:

Table 70: DNO Asset Health Score and Index Translation to EEA Asset Indicators

EEA asset health Indicator	DNO Methodology health index band	DNO Methodology, health index banding criteria	
		Lower limit of health score	Upper limit of health score
H5	HI1	≥0.5	<4
H4	HI2	≥4	<5.5
H3	HI3	≥5.5	<6.5
H2	HI4	≥6.5	<8
H1	HI5	≥8	≤10

H1-H5 are defined in the EEA's asset health indicator guide, as shown in the table below. The definitions in the EEA's guide correspond to the DNO Methodology for the respective health index band (albeit the numbering is in reverse order).

Table 71: Definition of EEA Asset Health Indicators[92]

EEA Asset Health Indicator Guide	
H1	A measure of asset health. End of serviceable life. Immediate intervention is required.
H2	A measure of asset health. Material deterioration but condition still within serviceable life parameters. Intervention likely within three years.
H3	A measure of asset health. Normal deterioration requiring regular monitoring, but with an increasing risk of failure.
H4	A measure of asset health. Normal deterioration requiring regular monitoring.
H5	A measure of asset health. As new condition.

92 EEA Asset Health Indicator defintion.

11.4 Assessing Asset Criticality

Asset criticality has been applied to individual assets using the methods identified in the EEA's "Asset criticality guide", which primarily ranks criticality according to five main categories: Public Safety, Workplace Safety, Direct Cost, Service Levels, and Environment.[93] Other factors which are identified as significant to criticality determination are:

- Distance to an asset from the depot (some areas take upwards of 3 hours to get to);
- Types of customers on a feeder (hospitals and emergency services).

Asset criticality is assigned within the range of C1-C4 to assets. C1 denotes assets that are most critical or have *no mitigating contextual factors,* and C4 indicates assets with *no plausible consequence of failure* (**CoF**) or *plausible CoF completely mitigated*.

Whilst assigning asset criticality has only recently been adopted, it is observable from historical renewal expenditure patterns that Firstlight had been focusing its expenditure on townships. Past renewal practices considered the risks (and potential consequences) of failure on public safety and service levels, which are typically greatest in townships and urban areas.

Asset criticality is progressively being used to enhance the renewal and maintenance forecasting and to guide the selection of specific projects. Combining asset health and asset criticality will produce a risk-based ranking order of asset renewal priorities that will more efficiently address the aging of assets. GIS capabilities are currently being upgraded to enable the visualisation of the risk matrix formulated through the combination of asset health and criticality. Expect to see risk reported in this manner in future iterations of the AMP.

11.5 Resilience Strategy

Climate change is affecting New Zealand's Infrastructure. Asset owners need to understand the impacts of climate change now and in the future and can adapt to ensure that New Zealand has the capability to adapt live and thrive in a more damaging climate. In this AMP, we have revised and enhanced our resilience strategy (refer to Section 10.9), which has implications for our lifecycle management.

The structures (wood and concrete) fleet has also been updated to reflect the changes to our resilience strategy in response to the increasing incidence of extreme weather due to climate change. We expect to include further changes to our fleet plan as our resilience work progresses.

11.6 Wood and Concrete Pole Fleet Plan

11.6.1 Changes in this AMP

For the 2023 AMP, the fleet strategy, asset risks and asset forecasting approach have been updated to incorporate relevant elements of the resilience strategy. The monitor, inspection, and maintenance plans are unchanged. The asset health, renewal and expenditure forecasts have been revised based on the latest condition data. The expenditure on this fleet has increased materially.

11.6.2 Fleet Overview

The pole fleet is a significant focus for Firstlight and has a significant role in maintaining a reliable supply of electricity to customers.

[93] EEA, "Asset Criticality Guide", 2019. The EEA definitions differ slighty to the Commerce Commission definitions. We have added clarity to the definitoin of H3 to recognise that the risk of failiure is increasing.

Consistent with a low-density network, most customers are served through the overhead network. The subtransmission system is 99% overhead, the distribution system is 93% overhead, and the LV system is 63% overhead.

48% of the overhead network utilises wood poles. Historically, the wood poles were Australian hardwood, but more recently, NZ softwood poles have been used.

Over the period 1990 to 2005, several ultra-sound or other quantitative methods were used to identify at-risk wood poles. This data was used to schedule the replacement of poor-condition and at-risk poles, and this work is essentially complete. This data is now considered obsolete.

During 2002, the mechanical strength requirements for all poles were calculated by Foley and recorded in the GIS. This work led to the replacement of poles that were carrying mechanical loads above their design rating. This data is used to confirm that any new pole installed in an existing location has the required design strength.

Pole replacements over the past decade have been focused on urban areas. Hence, the older population of distribution and LV poles are now typically in the urban fringe and rural areas.

In terms of private LV poles, the low socio-economic nature of the network area is contributing to the failure of private poles (which were gifted in the 90s) as there is little proactive renewal.

Steel structures (on the subtransmission network) are considered in a separate asset fleet plan. Refer to Section 11.7.

A separate vegetation management plan has been developed. Refer to Section 11.233.

11.6.3 Fleet Management Strategy

The 10-year pole fleet strategy is:

- Capture condition information on all poles using the new DNO methodology by 2025[94]and achieve 95% of all planned inspections from 2024 forward;
- Assess the asset health for all poles based on condition information using the DNO Methodology and revise the long-term forecasts each year as the asset condition data capture is completed;
- Ensure that there are no H1 assets present over the forecast period, and ensure that H2 assets are replaced before they deteriorate to H1;
- Ensure all defects (including red and blue tagged poles) are risk-assessed and replaced before failure. The target is to have no failures of any identified defective pole or pole tops;
- Identify all pre-2000 poles, assess the risk posed, revise asset health based on the risk, and prepare and implement a mitigation plan by 2025;
- Identify all priority areas (i.e. feeders or sections of feeders) using criticality, reliability, and asset health information and ensure that specified projects are identified for these areas;
- Improve the pole and pole-top failure rate on the subtransmission system and "backbone" distribution system;
- Develop a strategy to deal with the ageing private wood pole fleet.

The pole fleet strategy is consistent with the asset management strategy.

[94] The weather events and transition to Firstgas Group in RY2023 means that we will not meet the original RY2024 target. The target has been revised to RY2025.

11.6.4 How the asset fleet is operated, monitored and maintained

Operating The Assets

Pole structures form part of the overhead line system (that also includes conductors and various line switchgear and fuses). The overhead line system is operated via the control room, which monitors the voltage and load on the system and responds to faults. Faults are typically identified from the circuit breaker, recloser, sectionaliser operations and fault locators connected to the SCADA system. They are also reported by customers (via retailers or the call centre). Faultmen are dispatched to investigate and remediate the fault, and further escalation to effect repairs is initiated as required to restore supply.

Monitoring The Asset (Inspection and Testing)

Table 72 below summarises the pole fleet's current inspection and testing regime, excluding 110kV assets. The 110kV assets have more intensive inspection regimens). Refer to Table 79 for inspection programs in relation to these assets. Capturing condition information is largely time-based, with more frequent inspections of critical assets. Specific line patrols are initiated due to the unreliability of the line.

The pole inspection standards align with the DNO Methodology to ensure all the necessary observed condition inputs are captured, and these inputs are used to calculate the health of each asset to prepare accurate renewal forecasts using the DNO Methodology.

The pole inspection budget was increased in RY2022 to support the inspection of poles to be completed within three years. It is expected that expenditure will reduce to normal following the completion of this work.

Detailed pole inspections and patrols are qualitative assessments undertaken by suitably qualified and competent inspectors.

Table 72: Wood/concrete pole inspection/test programme

Voltage	Inspection Type	Scope of Inspection	Inspection Trigger
Sub-transmission (excluding 110kV assets).	Visual – patrol	Line patrols are undertaken via helicopter or vehicle-assisted ground patrols. The line patrols record any defective item (covering the observed condition inputs) and vegetation.	Unreliability of line. Following significant events.
	Visual – detailed	The capture of observed condition inputs in relation to overall visual pole condition, pole foundation, pole top, pole ground line, crossarm, insulators, stay wire, and other external factors (e.g. risk to the public). The observed condition inputs are consistent with the DNO Methodology for poles, including additional factors in relation to pole-top hardware. Verification of asset attribute data. Vegetation data is also captured. For wood poles, the visual inspection includes excavation or climbing as necessary to categorically determine the poles below ground or head condition.	Time-based, annually
	Wood pole testing	Currently, the judgement of experienced linesmen to test poles is used. Samples of the wood (below ground line) are taken and assessed based on standardised criteria,	Time-based. 3-yearly initially to populate DNO inputs, then 5-yearly

Voltage	Inspection Type	Scope of Inspection	Inspection Trigger
Distribution	Visual – patrol	The same as applied for subtransmission poles.	Unreliability of line. Following significant event
	Visual – detailed	The same as applied for subtransmission poles.	Time-based. 3 yearly initially to populate DNO inputs, then 5-yearly
	Wood pole testing	In conjunction with detailed visual inspections	As above
Low voltage	All types	LV poles are visually inspected in conjunction with the distribution pole inspection programme, with the same inspection standard applied.	As above

Maintaining The Asset

Pole maintenance typically includes defect repairs and scheduled pole-top hardware replacement, as shown in Table 73.

Table 73: Pole maintenance

Type of Maintenance	Maintenance Trigger
Defect repair	Defects are repaired following fault identification, line patrol, or detailed line inspection. The defect repair is assessed between the faultman and operator (in the case of a fault) and in coordination with the operations team in other cases. Defects are defined as remediation work on a pole that is required within one year. The scheduling of the repair is based on the risk of failure.
Crossarm, insulator replacement	Scheduled replacement of pole-top hardware (crossarms, insulator, binder, etc.) is made after reviewing the line patrol or detailed line inspection data.

11.6.5 How asset health is assessed

The DNO Methodology is used to determine current and five-year forecast asset health.

Asset health will be revised for those pre-2000 poles where it is determined that they cannot withstand windspeeds due to climate change.

11.6.6 How renewal decisions are made on the fleet

The specific drivers for asset health and renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 74.

Table 74: Drivers and triggers for renewal forecasts and projects

Renewal Item	Drivers/triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period and that H2 assets are replaced before they deteriorate to H1. Poles identified as poor (H2) are targeted to be replaced within three years[95]. Poles assigned H3, H4 or H5 are programmed into the future replacements based on the DNO modelling outcome. For the pole fleet, asset health is the primary driver for renewal forecasting; that is, there are no material type issues, latent safety issues, or obsolescence issues being considered at this time.

95 Replacement programmes are targeted at poles which have been assigned a health index value of H1 or H2. H2 poles are replaced in conjunction with planned shutdowns for H1 poles.

Renewal Item	Drivers/triggers
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following: • The most current inspection and asset health information (with this information being verified during the project concept phase); • Evidence that the pole(s) have deteriorated to the extent that their inherent mechanical strength is deteriorating; • Deteriorating reliability performance in respect of a particular feeder, or section of the feeder (where the underlying reasons for unreliability are attributable to deteriorating asset condition). These projects are prioritised after considering the criticality of the assets.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 12 months. Poles identified as *end-of-life* (H1) are identified with a red or blue tag, which signifies that the pole can support normal loads but not ultimate design loads. The targeted replacement of red-tagged poles is within three months. The targeted replacement of blue-tagged poles is within 12 months.

11.6.7 Fleet Performance and Risks

Current Fleet Performance

Pole faults were 7.4/10,000 poles in RY2023, the same as the average for the prior three years. There is no published asset fault rate data available for New Zealand. However, the asset fault rate is higher than Australia's unassisted pole failure rate (noting that the fault and failure rates are measurements of slightly different things). Reducing this fault rate is a worthwhile target, given the potential consequence of a pole fault.

Unplanned outages attributable to a pole being rotten or falling due to age are rare. It is usually an external interference such as a significant weather event, third-party interference, or vegetation-related incident that causes poles to fail.

There were no specific performance issues with the pole fleet on the subtransmission and LV networks.

Key Fleet Risks

The risk register has identified the following top risks in relation to poles (where the consequences are reliability or safety-related):

- Poor condition;
- Vegetation interference;
- Third-party interference;
- Insulator breakdown.

A key focus of this fleet plan is to ensure areas where risk levels are elevated, are identified and remediated before the risk occurs.

Some specific risk areas are being actively addressed:

- The potential for increased risk of failure for pre-2000 poles during cyclonic conditions;
- Rural settlements such as Te Araroa, Ruatoria, and Tokomaru Bay, which will now be the focus of the 400V Pole fleet;
- Wood poles above their maximum practical life (specifically on the subtransmission and distribution network);
- Private LV poles.

11.6.8 Fleet Population and Age

Details on the pole population and age profile are shown in Table 75. The asset management implications of the age and population are:

- 4,118 wood poles (24%) have exceeded their maximum practical life (**MPL**). While this is not necessarily an indicator of poor condition, it suggests that all poles must be inspected as soon as possible. Replacing over-aged wood poles (subject to condition) remains a focus of the pole renewal programme. These poles tend to be more concentrated on the rural feeders and, in conjunction with reliability analysis, will be the focus of efforts for the next couple of years.
- The current concrete pole population will not see any material percentage of poles reaching their MPL over the coming decade.
- 62% of all poles were installed before 2000. This indicates that further risk assessment will be needed to understand the extent of the windspeed risk to these lines.

Table 75: Pole asset fleet quantity and age

Voltage	Pole Type	Population	Average age (years)	MPL[96] (years)	No. of poles within 5-years of MPL
Subtransmission	Concrete	2,095	30.1	100	-
	Wood	1,364	36.7	60	461
Distribution	Concrete	13,399	24.0	100	-
	Wood	11,858	38.8	60	4,672
Low Voltage	Concrete	2615	19.3	100	-
	Wood	3787	36.4	60	1,086
Total		**35,118**	**30.9**	**-**	**6,219**

Note: This includes the 110kV concrete and wood structures but excludes the 110kV steel towers and privately owned poles.

11.6.9 Fleet Asset Health and Forecast Maintenance and Renewal Requirements

Asset health forecast (poles)

The asset health has been calculated using the DNO Methodology, with the results converted to the EEA's Asset Indices. The prior year, current and 5-year forecast of asset health (based on no renewals taking place) of the pole fleet is shown in Figure 107 and Figure 108.

The asset health of the fleet will continue to change as inspections (under the new methodology) are completed. The increase in the low-health wood poles is as expected and is consistent with our expectations as we inspect the older areas of the network.

[96] MPL means maximum practical life. Based on the EEA health determination for concrete and timber structure MPL.

Figure 107: Wood pole current and forecast asset health

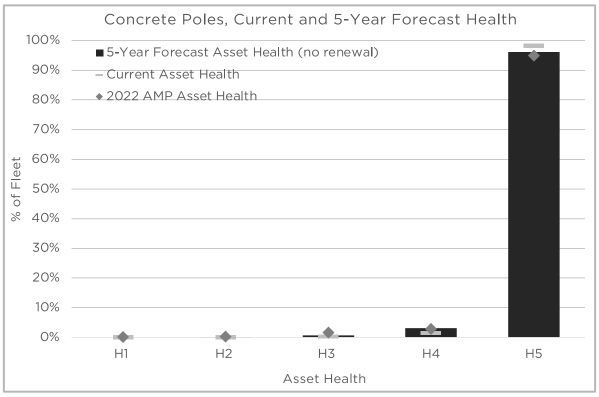
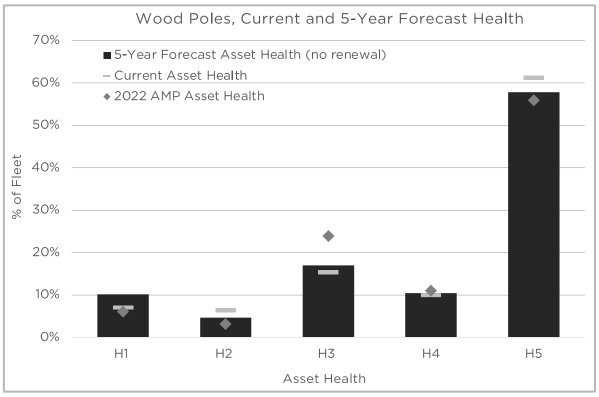


Figure 108: Concrete pole current and forecast asset health



Note: This includes the 110kV concrete and wood structures but excludes the 110kV steel towers & privately owned poles.

Asset replacement and renewal forecasts (Poles)

Table 76 shows the forecast pole asset health and replacements over the next five years. The pole renewals are forecast to keep pace with the H1 and H2 poles forecast over the period. The pole renewals are predominately focused on wood pole replacements. This is reinforced by observations that concrete poles are not failing prematurely, and we expect them to achieve their MPL without impacting reliability.

Based on current information, these forecasts are appropriate to maintain the fleet's health at an appropriate level to achieve safety, service (reliability), and efficiency objectives.

Note: This includes the 110kV concrete and wood structures but excludes the 110kV steel towers & privately owned poles.

Table 76: Forecast pole replacements

Voltage	Pole Type	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal[97]	Forecast pole renewals over the next 5-years[98]
Subtransmission	Concrete	2095	0	0	-
	Wood	1,364	217	278	368
Distribution	Concrete	13399	0	6	8
	Wood	11,858	1,901	2,071	2,744
Low Voltage	Concrete	2615	0	2	3
	Wood	3787	162	217	287
Total		**35,118**	**2,280**	**2,574**	**3,410**

Note: This includes the 110kV concrete and wood structures but excludes the 110kV steel towers & privately owned poles.

Accelerated wood pole replacement program

In the 2022 AMP, we accelerated the replacement of our wood pole fleet in response to the results of our inspection program (which was to a new, higher standard). Given the results of the most recent health assessments and the windspeed damage during cyclone Gabrielle (which was likely above design limits), we have further extended our wood pole replacement program. We plan to

[97] Note: Inspection process based on DNO methodology not due to be completed until 2024. Inspections will alter H1 & H2 forecasts for future works

[98] This includes both planned and unplanned replacements.

replace 20% of the fleet over the next five years, with over 8% of the fleet being replaced in the next two years. This is an increase of 480 poles. The additional cost of the program over that period is $8.6m.

Asset replacement and renewal forecasts (pole-top)

A key pole fleet activity is the renewal of pole-top hardware (i.e. crossarms and insulators). Mid-life renewal of pole-top hardware is typically required to enable the full economic life of the pole to be realised. Condition information is being captured in relation to pole-top hardware and developing the systems to report on this specific sub-asset with a view to including improvements in the 2024 AMP. At Firstlight, crossarm replacements are an opex expenditure.

Overhead to underground conversion

Firstlight continues with a program of overhead to underground conversion in township areas. The program is developed with stakeholder involvement.

Specific asset replacement and renewal projects

The engineering analysis of the most recent condition data, reliability data, and asset criticality has identified the material projects. Specific projects are identified for the first few years of forecasting, with little specificity in the outer years.

Over the next few years, the pole renewal program focuses on feeders impacted by storm damage, where reliability issues are apparent, and where there is a concentration of low-health poles. These feeders include:

- 50kV East Coast line;
- Hicks Bay;
- Tauwhareparae;
- Makaria;
- Tiki Tiki;
- Matawai;
- Waimatal
- Mata
- Tiniroto;
- Ngatapa;
- Lavernham;
- Kanakanaia;
- W-O-Kuri;
- Toki Tie;
- Raupuna;
- Frasertown;
- Dalton;
- Whatatutu.

11.6.10 Expenditure Forecasts

The pole fleet's asset replacement and renewal forecasts (opex and capex) are shown in Table 78 and Table 77 below.

Capex has been forecast based on the pole replacements forecast in Table76.

The capex forecasts are expected to change in response to the maturing of the asset health assessments and the completion of inspections under the new DNO methodology.

Table 77: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Subtransmission pole replacements	ARR	710	687	685	686	688
11kV pole replacements	ARR	3,071	3,320	3,311	3,316	3,324
Accelerated pole replacement program	ARR	3,255	2,767	1,041	1,042	1,045
LV pole replacement	ARR	264	263	262	263	263
Overhead to underground conversion	ARR	403	291	290	291	292
Total		**7,703**	**7,328**	**5,590**	**5,597**	**5,612**

Note: Constant 2023 $000.

Note: This excludes the 110kV concrete and wood structures. Includes planned and unplanned replacement. Refer to Table 85.

The opex forecasts relate to pole top replacements. This work is primarily on the subtransmission network. The Service interruption and emergency and Reactive and corrective maintenance and inspection forecasts are discussed in Section 14.

Table 78: Forecast Opex

Expenditure type	Opex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Pole-top replacement	ARR	22	22	22	22	22

Note: Constant 2023 $000.

Note: This excludes the 110kV concrete and wood structures. Refer to Table 86.

11.7 110kV Steel Structures

11.7.1 Changes in this AMP

For the 2023 AMP, the fleet strategy and asset risks have been updated, and additional geo-hazard management has been included. The expenditure on this fleet has increased materially.

11.7.2 Fleet Overview

Originating from the Tuai substation, Firstlight operates five 110kV circuits on its network. Two circuits supply the Wairoa substation, two supply the Gisborne substation, and one run from Gisborne to Tokomaru Bay (which operates at 50kV). The overhead conductor is supported by 477 steel towers, 64 concrete poles and 48 wood poles. The concrete and wood poles are predominantly located on the Gisborne plains as the mechanical loading and clearances are easier to obtain on level ground.

The circuits to Gisborne and Wairoa are N-1 electrically but not N-1 mechanically (as there are some shared structures). This increases the risk of loss of supply due to environmental factors.

The 110kV lines are critical lines for Firstlight, and as such, contracts have been set up with external specialist contractors to have crews ready to respond in case of an emergency.

11.7.3 Fleet Management Strategy

The 110kV steel structures are critical assets, and the 10-year fleet strategy is to:

- Monitor, inspect and maintain the line to good transmission line practices;

- Ensure that there are no H1 and H2 assets present over the forecast period and that H3 assets are replaced well before they deteriorate to H1 or H2;
- Ensure all defects are risk-assessed and replaced before failure. Our target is to have no failures of any identified defective item;
- Undertake a detailed risk assessment of the 110kV lines (including steel, concrete and wood structures) and remediate any high-risk areas;
- Proactively monitor and manage all geo-hazards.

11.7.4 How the asset fleet is operated, monitored and maintained

All maintenance and inspections of the 110kV structures are contracted to external contractors. The inspections in Table 79 apply to the steel, concrete and wood structures that form part of the 110kV line.

Table 79: 110kV line inspection/test programme

Inspection Type	Scope of Inspection	Inspection Trigger
Visual inspection	This visual inspection is generally undertaken on foot by specialist inspectors. The inspections look for: • Conductor clearances; • Slips; • Structure integrity; • Access track conditions; • Bird nesting and animal damage; • Bridge condition and access.	Annually
	Vegetation inspections are undertaken by foot and helicopter	6-monthly.
Site monitoring	High-risk sites have additional specific inspections or testing. (e.g. monitoring slow-moving slips and movement in water courses)	As required (as often as weekly), after weather events
Unplanned post-storm or post-tripping	Inspections are undertaken after every fault to determine the cause and to determine the required remediation	As required.
Condition Assessment	Detailed condition assessment includes hardware, conductor, structures, insulators and foundations. This is undertaken by specialist contractors that remove line hardware for detailed inspection	4 Yearly

Maintaining The Asset

Steel structure maintenance occurs in response to visual inspections, condition monitoring and faults. This would typically require specialist personnel and is generally planned well in advance (depending on the assessed risk of failure). Table 73 contains details of the types of inspections undertaken.

Table 80: 110kV steel structure maintenance

Type of maintenance	Scope of maintenance
Access track maintenance	Maintain access to towers, cut trucks if necessary, clearing vegetation, slips and culverts. Maintain landowner relationships and communications.
Foundation repairs and maintenance	Inspect grillage/foundations and below ground level equipment and repair as required.
Structure maintenance	Inspect componentry and identify replacement attachment requirements. Carry out CA and identification of any defects. Improve line clearance issues.

Insulator cleaning and string replacement	Insulators are replaced as part of capex work along with associated attachments in line with pole replacement schedules.

11.7.5 How asset health is assessed

The DNO Methodology is used to determine current and forecast asset health. This is augmented by the geo-hazard register, and the health of some towers is impacted by the current geo-hazards.

11.7.6 How renewal decisions are made on the fleet

The specific drivers for asset renewal forecasting and the triggers for specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 74.

Structure replacements are driven by intensive condition assessments, which identify all condition drivers. For the 110kV structures, Transpower's standards and processes for the condition assessments of steel towers continue to be used.

Table 81: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period and that H2 assets are replaced before they deteriorate to H1. The detailed condition assessment is the primary driver of this. Assets or components of the assets (i.e. foundation, structure, insulators) that have been identified as being poor (H2) are targeted to be replaced within 1-4 Years (depending on the assessed risk)[99]. Assets (or components of the assets) assigned H3, H4 or H5 are programmed into the future replacements based on assessed risk.
Renewal and maintenance projects	Specific renewal or maintenance projects are defined and selected based on the current condition assessments or specific site monitoring. The scheduling of these projects is made after considering the risk of failure.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 12 months.

11.7.7 Fleet Performance and Risks

Current Fleet Performance

The 110kV lines are critical assets. The criticality of the line drives the continual inspection, maintenance, and replacement programme to ensure that the structures remain in good operating condition.

Key Fleet Risks

The risk register has identified the following top risks in relation to 110kV structures (where the consequences are reliability or safety-related):

- Geo-hazards (landslips and erosion);
- Third-party interference (planes);
- Wildlife (birds and animal damage);
- Environmental factors (snow, ice;
- Unobserved deterioration in condition.

99 Replacement programmes are targeted at poles which have been assigned a health index value of H1 or H2. H2 poles are replaced in conjunction with planned shutdowns for H1 poles.

For the 110kV tower lines, we have a separate geo-hazard risk register that identifies all the known geo-hazards and the associated monitoring, controls and remediation plans. Risks are principally managed through the inspection and condition monitoring regime. Known risk areas (e.g. structures exposed to slow-moving slips or water cause movement) have specific monitoring programs.

Given the criticality of these assets (in relation to the N mechanical security of some structures), a detailed risk study was undertaken during RY2022. The extreme weather events in RY2022 and RY2023 resulted in new geo-hazard locations that are being managed.

Presently, six active geo-hazards require mitigation and five other sites are being monitored, and mitigation plans are in place. Eight of these sites are on the GIS-TUI-A line. Remediation work on these sites is planned or underway.

11.7.8 Fleet Population and Age

Details on the steel structure population and age are shown in Table 82.

Table 82: 110kV steel structure asset fleet quantity and age

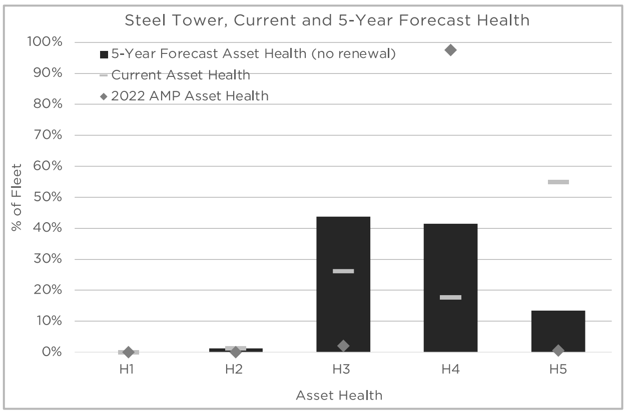
Line	Structure type	Population	Average age (years)	MPL[100] (years)	No. of structures within 5-years of MPL
GIS-TUI-A	Steel towers	211	58	90	0
GIS-TOKO	Steel towers	208	44	90	0
WRA-TUI-A	Steel towers	58	47	90	0
Total	**-**	**477**	**50**	**90**	**0**

11.7.9 Fleet Asset Health and Forecast Renewal and Remediation Requirements

The current asset health for steel structures is shown in Figure 109. The health assessment of the steel structures has been assessed using the DNO methodology. The asset health assessment has changed materially as the DNO Methodology has been applied to this fleet.

100 MPL means maximum practical life. Based on the EEA's health determination for iron rail. Note there is no definitive MPL for steel structures.

Figure 109: 110kV steel structure asset health[101]



There are presently two H2 towers and four H2 foundations. A new tower (in a new location) is required at T11 on the GIS-TUI-A line and at T13 on the GIS-TOB-A line. All of these towers and foundations are forecast for remediation within three years.

There are five H3 foundations where geo-hazards are being actively monitored. These sites have monitoring and mitigation plans in place. Mitigations may be required within the forecast period.

Table 83: Forecast tower and geotechnical replacement and remediation

Type	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal[102]	Forecast renewals over the next 5-years[103]
Steel tower replacement	477	2	2	2
Foundation and geotechnical remediation	-	4	4	4

Table 84: Forecast tower and geotechnical work

Type	Total population	Grade H3 assets (2023)	Forecast grade H3 assets (2027) before renewal[104]	Forecast renewals over the next 5-years[105]
Foundation and geotechnical remediation being actively monitored	-	5	5	n/a

11.7.10 Expenditure forecasts

The asset replacement and renewal forecasts (opex and capex) for the pole fleet are shown in Table 85 and Table 86 below. The expenditure forecasts for the 110kV tower structures are consistent with the health assessments and geo-hazards risk mitigation. The forecasts include the ongoing programme of condition assessment, access track maintenance, foundation maintenance, structure maintenance and insulator maintenance, as set out in Table 80. The expenditure is appropriate to ensure that the fleet's health is sufficient to maintain performance at least consistent with historical levels.

101 The DNO methodology has been adopted, which has resulted is a significant change from previous heath profiles. The DNO output had assigned some H5 assets. We have categorised these as H4 duer to the age of the lines.
102 Note: Inspection process based on DNO methodology not due to be completed until 2024. Inspections will alter H1 & H2 forecasts for future works
103 This includes both planned and unplanned replacements.
104 Note: Inspection process based on DNO methodology not due to be completed until 2024. Inspections will alter H1 & H2 forecasts for future works
105 This includes both planned and unplanned replacements.

Table 85: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Tower replacement and geo-hazard remediation	ARR	469	375	270	104	-
Grillage/Foundation Replacement	ARR	144	143	143	143	143
Insulator and Structure Replacement and Repairs	ARR	202	183	182	182	183
Access tracks and bridge repairs and replacements	ARR	500	300	461	-	-
Total		**1,315**	**1,000**	**1,056**	**429**	**326**

Note: Constant 2023 $000

Table 86: Forecast Opex

Expenditure type	Opex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Access track maintenance	RCMI	30	30	31	76	31
Tower and foundation maintenance	RCMI	200	162	164	162	164
Condition assessments	RCMI	177	207	-	206	-
Total		**407**	**398**	**195**	**443**	**195**

Note: Constant 2023 $000

11.8 Conductor Fleet Plan

11.8.1 Changes in this AMP

The fleet has transitioned to the DNO Methodology for current and forecast asset health and renewals.

11.8.2 Fleet Overview

The Firstlight network operates at five different voltage levels. The length of the 110kV is 307 km, the 50/33kV line is 346 km, the 11kV is 2,387km, and the 400V is 505km long. The conductor is sized to carry the required load within the capacity of the conductor and voltage limits for the line.

The 110kV line is mainly "Dog" and "Hyena" and links Tuai and the main regions. As these are critical assets for Firstlight, maintenance inspections and vegetation management are closely monitored. The majority of these lines retain the original conductor. The inspections show that the line is still in good condition.

The subtransmission 50/33kV line is primarily built using ACSR conductor (e.g. "Mink" and "Dog") with some minor runs of 19/14 Cu. The lines operate as the links between the zone substations.

The distribution network was built using many different types of conductors. Some coastal areas were built using copper conductors, and these lines are showing signs of significant corrosion.

The low voltage network (230/400V) is used to supply most customers. The 400V circuits are usually quite short due to the voltage drop at this voltage level. This means distribution transformers are located throughout the network to ensure electricity is supplied at 230V +/- 5%.

11.8.3 Fleet Management Strategy

The 10-year conductor fleet strategy is to:

- The transition from historical age-based forecasting to health-based and reliability-focused renewal forecasting. This requires:
  - (a) Capture condition information on all HV (11kV & above) conductors using the new DNO methodology by RY2025 and achieve all planned inspections going forward;
  - (b) Assess the health of all conductors based on condition information using the DNO methodology and revise the long-term forecasts by 2025;
- Ensure that there are no H1 assets present over the forecast period;
- Ensure all defects (fraying conductor, material type issues) are risk assessed and replaced before failure;
- Identify areas where load growth occurs and plan proactive upgrades where capacity may become an issue.

The vegetation management plan supports the conductor fleet plan.

The conductor fleet strategy is consistent with the overall asset management strategy for the network.

11.8.4 How the asset fleet is operated, monitored and maintained

Operating the assets

Conductors form part of the overhead line system (that also includes poles and various line switchgear and fuses). Current through the conductors is at zone substations and reclosers. Alarms notify control room staff should currents or voltage levels in the conductor reach levels beyond the operating limits.

Monitoring The Asset (Inspection and Testing)

Table 87 below summarises the conductor fleet's current inspection and testing regime. The conductor inspection programme is heavily aligned with the pole inspection programme in that they are done simultaneously while the inspector is on-site.

Table 87: Conductor inspection/test programme

Voltage	Inspection type	Scope of inspection	Inspection trigger
Subtransmission	Visual – Patrol	Line patrols are undertaken via helicopter or vehicle-assisted ground patrols. The line patrols record any defective item (covering the observed condition inputs) and vegetation.	Unreliability of line
	Visual – Detailed	Capture of observed condition inputs in relation to overall visual conductor condition, conductor fraying, fatigue (due to wind movement), chafing, corrosion (age and coastal factors), and number of joints within the span. The observed condition inputs are consistent with the DNO Methodology. Verification of asset attribute data (mainly conductor type). Vegetation data is also captured.	In line with the pole inspection programme
	Conductor testing	Reliability analysis will show where hotspots on the network are arising. Where necessary, samples will be taken to determine the remaining strength within the conductor.	Unreliability of line

Voltage	Inspection type	Scope of inspection	Inspection trigger
Distribution	Visual – Patrol	Same as applied for subtransmission conductor. Helicopter patrols are conducted when access to the site is limited via vehicles.	In line with the pole inspection programme
	Visual – Detailed	Same as applied for subtransmission conductor	In line with the pole inspection programme
	Conductor testing	Same as applied for subtransmission conductor	Unreliability of line
Low voltage	All types	LV conductors are visually inspected in conjunction with the distribution conductor inspection programme. Testing is not and will not be, performed on this conductor as spans are not usually too long due to volt drop.	In line with the pole inspection programme

The GIS data for conductors is updated on a per-span basis. Therefore, confirmation of conductor type is undertaken during inspection to ensure the load flow models for the network are up to date.

Maintaining The Asset

Conductor maintenance typically consists of defect repairs.

Table 88: Conductor maintenance

Type of maintenance	Maintenance trigger
Defect repair	Defects are repaired following identification following a fault, line patrol or detailed line inspection. The assessment of the defect repair is made between the faultman and operator (in the case of a fault) and between the faultman and senior project manager in other cases. Defects are defined as remediation work on the conductor that is required immediately.

11.8.5 How the asset health is assessed

The DNO Methodology is used to determine current and forecast asset health. However, for this asset fleet, the primary driver is for replacement to ensure reliability is maintained appropriately.

Assessing the condition of conductors is complex, and Firstlight will adopt industry best practice for condition assessments when this becomes available.

11.8.6 How renewal decisions are made on the fleet

The drivers for asset renewal forecasting and the triggers for specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 89.

Table 89: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/Triggers
Health forecasts	The DNO Methodology is used to forecast asset health (in five years).
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period. For the conductor fleet, asset health and reliability are the primary drivers for renewal forecasting. Several conductor types have been identified as a material risk. We are determining the criticality of the lines they are on to determine if replacement is required.
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following:

Renewal item	Drivers/Triggers
	• The most current inspection and asset health information (with this information being verified during the project concept phase); • Deteriorating reliability performance in respect of a particular feeder, or section of the feeder (where the underlying reasons for unreliability are attributable to deteriorating asset condition); • Trend analysis shows that load growth is beyond predictions and loads are approaching maximum current carrying capacity; • Material type issue or specific risk. Inspection of the line is undertaken before confirming specific renewal projects. The prioritization of these projects is made after considering the criticality of the assets.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 12 months. Conductors which have been identified as EOL (H1) is noted in the defect register. Project managers and engineers determine whether span or line segment replacement is required.

11.8.7 Fleet Performance and Risks

Current Fleet Performance

Analysis of the reliability data indicates that the conductor fault rate is 1.2 faults/100km/year, which is favourable when compared to the historical average of 1.6 faults/100km/year. Most outages were caused by conductor failure, with a smaller contribution from connector (joints and jumper) failure. Refer to Section 6 for further details.

An initial study of the fault types showed a mix of condition-related failure and failure at joints in the line. Based on these failure modes, areas for improving performance include:

- ensuring that the right crimps are used on the correct wire;
- increasing inspections;
- working with faultmen / linemen to gather insight from their experiences on the network.

Key Fleet Risks

The risk register has identified the following top risks in relation to conductors (where the consequences are reliability or safety-related):

- Poor condition;
- Poor workmanship;
- Vegetation interference;
- Third-party interference (high loads);
- Coastal environment.

A key focus of this fleet plan is to ensure areas, where risk levels are elevated, are identified and remediated before the risk occurs.

In terms of specific risk areas which are being actively addressed:

- Conductor height clearance compliance with ECP 34 in relation to 11kV and 400V road crossings;
- No.8 steel wire. This conductor type has been identified as a material network risk because it is starting to rust and fail. The No.8 wire on the main line feeders has been replaced. We are currently monitoring the reliability of the No.8 wire on spur line feeders.

11.8.8 Fleet Population and Age

Details on the conductor populations and conductor age profile are shown in Table 90. The asset management implications from the age and population are:

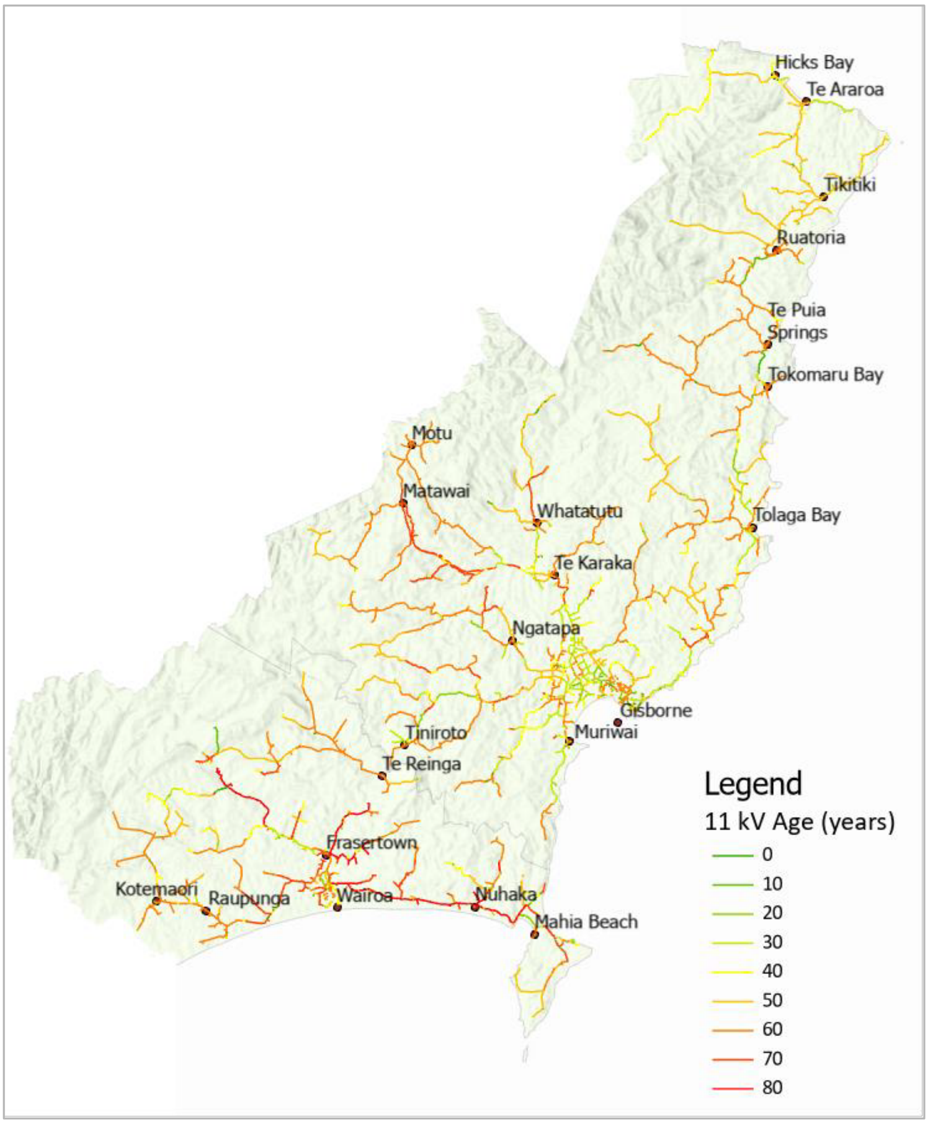
- Most of the original lines were built using copper. This is indicated in the average age profile for the different material types;
- Coastal regions with copper conductors must be monitored carefully for signs of significant deterioration or trends in defective equipment failures.

Table 90: Conductor asset fleet quantity and age

Voltage	Conductor type	Length (km)	Average age (years)	MPL[106] (years)	Length within 5 years of MPL (km)
Sub-transmission (110kV)	ACSR/AAC/AAAC	307	58	70	103
	Copper	0	-	80	-
Sub-transmission (50/33kV)	ACSR/AAC/AAAC	330	47	70	45
	Copper	6	40	80	-
Distribution	ACSR/AAC/AAAC	1297	48	70	254
	Copper	1080	58	80	134
Low Voltage	ACSR/AAC/AAAC	122	48	70	17
	Copper	381	55	80	37
SWER	ACSR/AAC/AAAC	0	0	70	-
	Copper	1	41	80	-
Total		**3,524**	**-**	**-**	**590**

[106] MPL means maximum practical life. Based on the DNO methodology for conductor.

Figure 110: Geographical map of the 11kV Network



11.8.9 How we forecast asset health

The asset health has been calculated using the DNO Methodology.

11.8.10 Fleet Asset Health and Forecast Renewals

Asset replacement and renewal forecasts (conductor)

The current and forecast asset health for the conductor fleet is shown in Figure 111 to Figure 114. The change to the DNO Methodology is the reason for the difference in health from the previous AMP. The asset health of the fleet is expected to continue to change as inspections (under the new methodology) are completed.

Figure 111: Subtransmission (110kV) conductor asset health

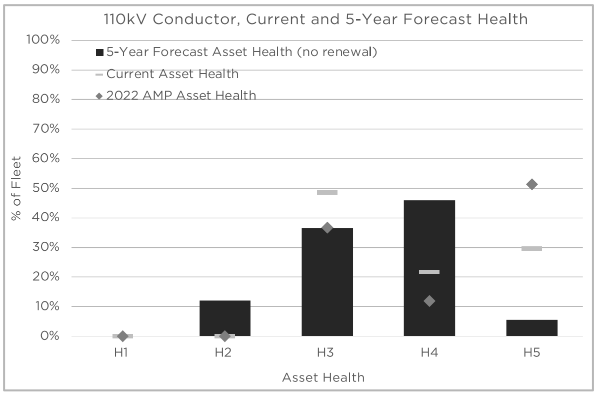


Figure 112: Subtransmission (50/33kV) conductor asset health

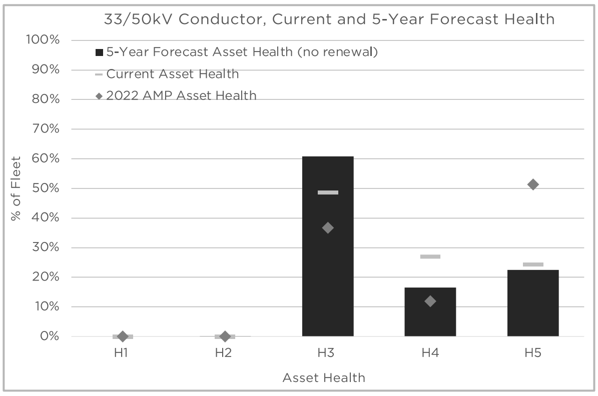


Figure 113: Distribution (11kV) conductor asset health

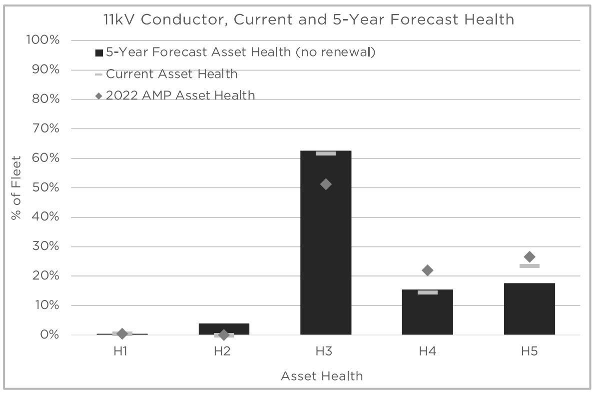


Figure 114: Low Voltage (400V) conductor asset health

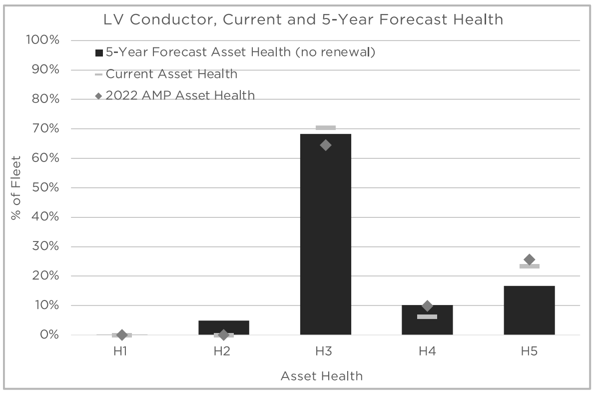


Table 91 shows the forecast conductor asset health and replacements over the next 5 years. This indicates that around 165km of conductors will transition from H3 to H1/H2 over the next 5 years.

Presently, the forecast of renewals for 40km over the next 5 years. This is below the expected quantity of conductors that will transition to H1/H2 over the next 5 years (and below the expected quantity of conductors that will reach MPL over the next 5 years). Presently, these forecasts are considered appropriate to maintain the fleet's health at an appropriate level as forecasts are consistent with prior years, and failure rates do not indicate systemic issues. However, the intention is to review the conductor renewal forecasts as inspections are completed, and asset health data is updated.

Table 91: Forecast conductor replacements

Voltage	Total Length (km)	Grade H1 & H2 assets (2023) (km)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast conductor renewals (km) over the next 5 years[107]
Sub-transmission (110kV)	307	-	-	-
Sub-transmission (50/33kV)	336	-	37	-
Distribution	2377	10.1	102	32
Low Voltage	503	0.3	25	7.8
SWER	0.7	-	0.7	0.2
Total	**3524**	**10.4**	**165.0**	**40**

107 This includes both planned and unplanned replacements.

Specific asset replacement and renewal projects

Specific projects are determined from engineering analysis of the most recent condition data, reliability data, and asset criticality. The current reconductoring is planned in the Mahia, Fastertown, Ngatapa, Matawai and coastal feeder on the East Coast.

11.8.11 Expenditure Forecasts

The forecast expenditure for the conductor fleet is shown in Table 92 below.

Capital expenditure allows for 8km of conductor replacement annually to RY2028. As condition data and health forecasting improve, these forecasts will be revised in future AMPs.

Table 92: Forecast capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Conductor replacement Gisborne	ARR	288	332	331	331	332
Conductor replacement Wairoa	ARR	139	139	138	139	139
Total		**427**	**471**	**469**	**470**	**471**

Note: Constant 2023 $000.

Note: Conductor renewal is also undertaken in the OH to UG conversions. This work is forecast in the structures (poles) fleet.

Note: the Ngatapa to Matawhi link includes conductor renewal. This work is forecast in the development plan.

Forecasts for conductor fault repairs, inspection and maintenance are included within the general network opex forecasts contained in Section 14.

11.9 Underground Cables

11.9.1 Changes in this AMP

Other than updating current and forecast asset health and renewals, there have been no material changes to the cable fleet plan since the 2021 AMP.

11.9.2 Fleet Overview

Firstlight's underground cabling is primarily in the main CBD and newer urban areas of Gisborne and Wairoa. Some smaller townships, such as Ruatoria and Mahia, have small sections where the overhead lines have been converted to underground. The primary driver is reducing public exposure to overhead network assets.

Most zone substations have underground cables connecting the circuit breakers to the overhead lines outside the substation.

The subtransmission network has one cable section that runs under the Gisborne River and provides the ring connection between the Kaiti/Port Substations and Carnarvon. This cable was installed in 2005 and is in good condition. Regular thermal condition assessments are performed on this cable termination to monitor its integrity.

11kV cables link between ground-mounted switchgear and distribution transformers. The switchgear allows sections to be isolated and earthed. 400V cables connect distribution transformers, LV links and customer pillar boxes.

Staff are trained in using the cable fault locator and acoustic ground detection systems so that the necessary capabilities are on hand to locate the fault.

11.9.3 How the asset fleet is operated, monitored and maintained

SCADA and GIS systems hold the information for the underground network. The load on 11kV cables is monitored at zone substations via SCADA. Alarms within the control room notify operators when loads reach cable capacity. The load on 400V cables is monitored via MDI on ground-mounted distribution transformers, which are checked during transformer inspections.

Table 93: Underground cable inspection/test programme

Inspection type	Scope of inspection	Inspection trigger
Inspection	Inspect switchgear terminations in cases where discharge can be heard	Based on the GM switchgear inspection programme
Inspection	Thermal imaging of subtransmission termination points	Time-based – Annually

Table 94: Underground cable maintenance programme

Inspection type	Scope of maintenance	Maintenance trigger
Maintenance	Remove and clean cable terminations. The scope of work is dependent on the condition of the cable.	Based on the GM switchgear inspection programme

11.9.4 How asset health is determined

For the cable fleet, asset health is primarily determined by age and specific condition inputs where these are available. The cable construction and insulation type impact the MPL used. Condition is derived from cable faults (i.e. repeat fault on a section of cable) and insulation and discharge testing.

11.9.5 How renewal decisions are made on the fleet

Repeat cable failures are the primary driver for the replacement of a cable. When multiple failures are experienced on a section of cable, the condition is reviewed, and replacement is typically scheduled.

11.9.6 Fleet Performance and Risks

Current Fleet Performance

The dominant failure mode for underground cables is insulation failure of the Reychem terminations. Post fault analysis indicates wet weather followed by hot humid weather is the main trigger. Open point terminations on switchgear appear to be more vulnerable than loaded terminations.

Inspections of terminations require shutdowns. However, early identification of issues would often be unsuccessful as the detectable condition deterioration is quickly followed by failure, and time frames are shorter than practical inspection frequencies.

Alternative heat-shrink products and terminations using rollup or cold boot insulation have been tried, with no apparent improvement in reliability. As improved products become available, they may reduce the issues over time. However, in the medium term, no performance improvement is expected. Some modern switchgear designs have increased the clearances around terminations, which may improve performance. Potentially real-time discharge monitoring equipment and low-cost communications options could be developed to detect discharge. However, no suitable products have been identified to date.

Key Fleet Risks

The risk register has identified the following top risks in relation to zone substations (where the consequences are reliability or safety-related):

- Insulation failure of cable terminations;
- Thermal overloading;
- Cable installation methods;
- Ground conditions.

Firstlight is actively assessing and addressing cable terminations through the switchgear inspection and maintenance programme.

11.9.7 Fleet Population and Age

The fleet population and age are shown in Table 95. MPLs differ for PILC, XLPE, and PVC cables.

Table 95: Cable asset fleet quantity and age

Voltage	Cable type	Length (km)	Average age (years)	MPL[108] (years)	Length within 5 years of MPL (km)
All	PILC	104	32	100	0
All	XPLE	42	29	60	5
All	PVC	313	29	60	10
Total	**-**	**459**	**30**	**-**	**15**

11.9.8 Fleet Asset Health and Forecast Renewals

The current and forecast asset health are shown in Figure 115.

Figure 115: Subtransmission (XLPE) cable asset health

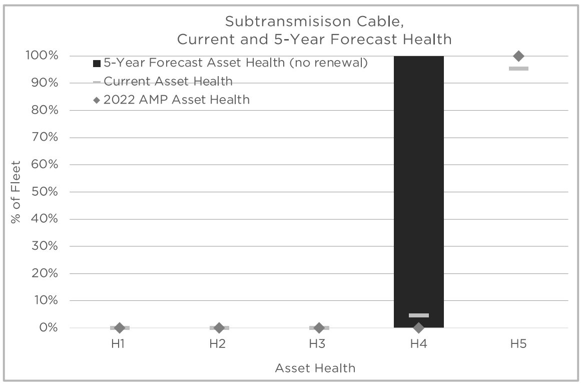
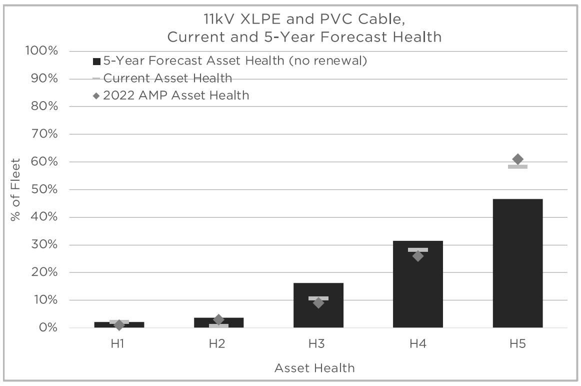


Figure 116: 11kV (XLPE and PVC) cable asset health



108 MPL means maximum practical life. Based on the EEA health determination for cables MPL.

Figure 117: 11kV (PILC) cable asset health

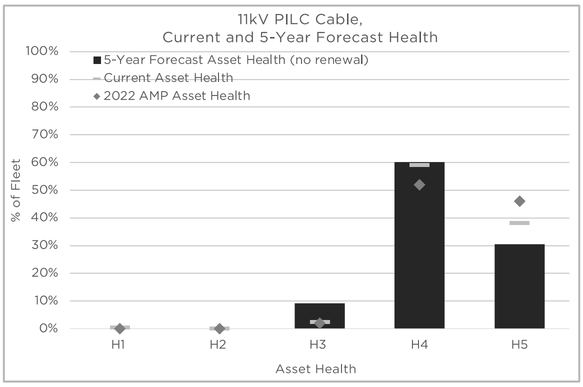


Figure 118: LV cable asset health

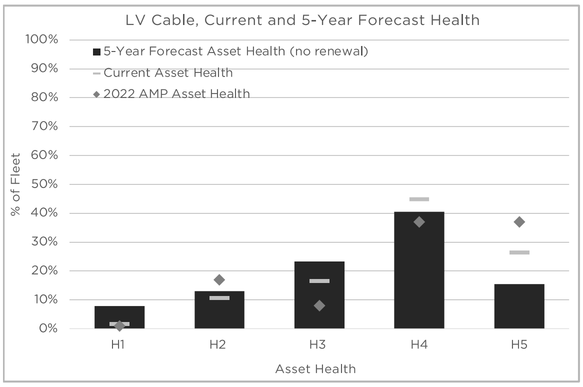


Table 96 shows the forecast cable renewals. Presently, we are forecasting cable renewals below the forecast for H1 and H2 assets.

Table 96: Forecast cable renewals

Voltage	Asset category	Total Length (km)	Grade H1 & H2 assets (2023) (km)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast cable renewals (km) over the next 5 years
Subtransmission	XLPE	1.4	-	-	-
11kV	XLPE and PVC	40	1.2	2.3	2.5
11kV	PILC	101	0.5	0.5	-
LV	PVC	277	34	57	5.0
Total	**-**	**422**	**33**	**60**	**7.5**

11.9.9 Expenditure Forecasts

The forecast expenditure for the cable fleet is shown in Table 97 below. These are general allowances based on historical trends, as there are no specific projects identified. As condition data and health forecasting improve, these forecasts will be revised in future AMPs.

Table 97: Forecast capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
HV Cable replacement	ARR	114	114	113	114	114
LV Cables replacement	ARR	92	92	92	92	92
Total		206	206	205	205	206

Note: Constant 2023 $000.

Forecasts for cable fault repair, inspection and maintenance are included within the general network opex forecasts contained in Section 14.

11.10 Power Transformers

11.10.1 Changes in this AMP

Other than updating current and forecast asset health and renewals, there have been no material changes to the power transformer fleet plan since the 2021 AMP. 92% of the fleet has been inspected to the new DNO standard.

11.10.2 Fleet Overview

The power transformer fleet makes up approximately 4% of the overall assets by value. Individually, these are the most valuable assets. Power transformers have a heavy initial investment as well as high operational costs. Therefore, significant consideration and assessment are performed before purchasing new transformers.

In the late 1990s and early 2000s, Firstlight installed IMP-type transformers. We believe these transformers will not reach their MPL without intervention (i.e. refurbishment). Considering this, our maintenance programs incorporate regular painting and tap-changer maintenance to prevent premature failure of the units. As part of this maintenance, custom manufacturing of parts (resistors, contacts, roller assemblies etc.) is required, as parts cannot be sourced from the original manufacturer.

Currently, Firstlight has a major overhaul programme underway for the power transformers.

11.10.3 Fleet Management Strategy

The 10-year power transformer fleet strategy is:

- Replace or remove all assets identified as a material type risk within the planning period (see risk section and commentary above);
- All assets should be renewed or refurbished before reaching H1 health, and all H2 assets are renewed or refurbished quickly;
- Actively monitor the health of the asset fleet and prevent or minimise premature failures;
- Design foundations and mounts to create interchangeable pads for all new transformers;
- Develop and complete maintenance programs consistent with the manufacturer's guidelines and Firstlight's standards to ensure assets are kept in a reliable condition;
- Ensure transformer sizes are consistent with forecast load growth.

11.10.4 How the asset fleet is operated, monitored and maintained

Operating The Assets

Power transformers are one of the primary assets within a zone substation (which also includes switchgear, secondary assets, and measurement equipment). The operation of a power transformer is through its tap-changer, which is used to regulate the voltage output depending on the load it is supplying and the settings provided within the controller. As the only moving part within a transformer, the tap-changer is more susceptible to faults than other components. Faults for power transformers are identified through SCADA monitoring of the protection devices. This usually includes Buchholz relays, pressure relief valves (PRV), and tap-changer overload relays. Faults on transformers can vary in criticality, and technicians are dispatched to the site to investigate the cause of a fault should monitoring equipment be unable to provide adequate information.

Monitoring The Asset (Inspection and Testing)

Table 98 summarises the power transformer fleet's current inspection and testing regime. Observed condition information is captured through four-monthly inspections of the zone substation sites, and measurement-based condition information (such as DGA's) is captured bi-annually.

The power transformer inspection standards were updated during RY2021 to align with the DNO Methodology to ensure all the necessary observed and measured condition inputs were captured.

Table 98: Power transformer inspection/test programme

Asset	Inspection type	Scope of inspection	Inspection trigger

Power Transformer	Visual – Inspection	Routine inspection to check for oil leaks, rust and corrosion, Oil levels, correct tap changer operation and indication. Completed as part of the zone substation inspection programme	4 monthly
	Measurement	Thermovision of connection points / Hot spots	Annually
	Measurement	DGA and Furan analysis	2 yearly

Appropriately qualified technicians perform visual inspections. External contractors perform the tests and measurements.

Maintaining The Asset

Power transformer maintenance typically consists of work associated with the tap-changer. Planned maintenance is based on the manufacturer's recommendations for frequency and test types.

Table 99: Power Transformer maintenance

Type of maintenance	Maintenance trigger
Defect repair	Defects are repaired following identification following a fault or inspection. The assessment of the defect repair is made between the technician and the substation engineer The scheduling of the defect repair is based on the risk of failure.
Tap-changer maintenance	Maintenance on tap-changers is completed every 5 years and includes oil replacement, cleaning of components, removal of arcing products, contact alignment and tap resistance.
Planned maintenance	Scheduled every 5 years, including a detailed inspection of components, checking operation of secondary equipment, insulation resistance, Winding resistance, etc. Usually worked in conjunction with the tap-changer maintenance. Usually completed as part of transformer commissioning. A budget to sandblast and paint the IMP transformers is included to reduce the effects of the corrosion.

11.10.5 How asset health is assessed

The DNO Methodology is used to determine current and forecast asset health. For this fleet, appropriate observed and measured condition inputs are used to calculate asset health.

11.10.6 How renewal decisions are made on the fleet

The DNO Methodology is used to forecast asset renewals. The specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 100.

Table 100: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period and that all H2 assets are renewed or refurbished quickly. Factors that contribute to the renewal of power transformers include: • Aging transformers; • Material type issues; • Unreliability; • Condition monitoring. For the power transformer fleet, the renewals are based on the health and criticality of the assets.

Renewal item	Drivers/triggers
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following: • The most current inspection and asset health information (with this information being verified during the project concept phase); • Inspections and planned maintenance identify issues with the transformer, suggesting that the material, structural integrity or performance of the power transformer has reached a point where the risk of failure has become unacceptable; • Deteriorating reliability performance (where the underlying reasons for unreliability are attributable to deteriorating asset condition); Because of the criticality and value of these assets, they are scheduled for replacement or refurbishment following a project feasibility study (which includes the same factors required for the refurbishment study below).
Refurbishment projects	Refurbishment of power transformers is required when determination of the following factors has been considered: • Capacity still within required load growth forecasts; • Current value of transformer; • Age; • Performance or condition issue driving refurbishment; • Type.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months. It is identified in the strategy for the fleet that transformers should not reach a point where their performance and risk of failure is compromised. However, Firstlight maintains strategic spares and relies on substation security (backup supply or dual transformers) when and if a failure is to occur.

11.10.7 Fleet Performance and Risks

Current Fleet Performance

The power transformer fleet performance is generally good. No issues with the main components, such as the main tank, windings, or core, have been identified. Issues with the tap-changers and secondary measurement components have been experienced, and the tap-changers on the IMP transformers are at risk of failure. Strategic spares are stored in the event of a breakdown.

Key Fleet Fisks

The risk register has identified the following top risks in relation to power transformers (where the consequences are reliability or safety-related):

- Tap changer breakdown;
- Rust and corrosion;
- Oil leaks and gasket breakdown;
- Transformer age;
- Component spares on some of the transformer types.

In terms of specific risks that are being actively addressed:

Table 101: Specific power transformer risks

Active Risk	Actions taken to minimise or mitigate risk
Single Phase transformer banks (condition and spare parts)	All aging single-phase units are scheduled for replacement within the forecast period

Premature failure of IMP tap-changer components (Split pins, roller assemblies, resistors and contacts)	Regular maintenance programme on tap-changers, procurement of spare parts. Upgrade of split pins during maintenance outages.

11.10.8 Fleet Population and Age

Details on the power transformer populations and age profile are shown in Table 102. The implications from the age and population are:

- Following recent transformer replacements (since the 2021 AMP) only one zone substation is operating power transformers forecast to reach MPL over the next five years. While age is not necessarily an indicator of poor health, recent inspections and type issues have indicated that drivers for replacement are present. Replacing these three single-phase transformers will remove a significant risk;
- IMP transformers make up 38% of the asset fleet but have been identified as being a lot more susceptible to rust and corrosion. A noticeable trend (discovered through maintenance and fault repairs) is that the tap-changer split pins are failing prematurely. Refurbishment of these transformers will likely be required to achieve their MPL.

Table 102: Power transformer asset fleet quantity and age

Type	Type	Population	Average age	MPL[109]	No. of transformers within 5-years of MPL
Power Transformer	IMP	14	20	65	0
	Single Phase Units	11	39	65	3
	Other	11	20	65	0

11.10.9 Fleet Asset Health and Forecast Maintenance and Renewal Requirements

Asset replacement and renewal forecasts (Power Transformers)

The current and forecast asset health for the power transformer fleet is shown in Figure 119.

Figure 119: Power Transformer asset health[110]

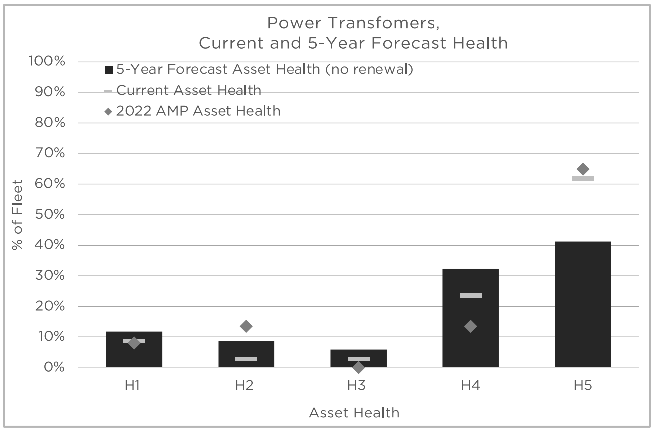


Table 103 shows the forecast power transformer asset health and replacements over the next five years. The power transformer renewals are forecast to keep pace with the forecast H1 and H2 assets over the period.

109 MPL means maximum practical life. Based on the EEA health determination for Power Transformers MPL.
110 Single phase transformers are reported on separately.

Based on current information, these forecasts are appropriate to maintain the fleet's health at an appropriate level to achieve safety, service (reliability), and efficiency objectives.

Table 103: Forecast power transformer renewals

Asset category	Type	Quantity	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028), before renewal	Forecast transformer renewals over the next 5 years[111]
Power transformer	IMP	14	1	3	3
	Single Phase Units	11	3	3	3
	Other	10	-	-	-
Total		**45**	**4**	**6**	**6**

Specific asset replacement and renewal projects

The engineering analysis of the most recent condition data, reliability data, and asset criticality has identified the material projects shown in Table 104. Additional to this is the installation of two substations at Massey Rd and Whangara, which require the addition of two extra transformers.

These specific projects align with the fleet strategy described in Section 11.10.3.

Table 104: Specific asset replacement and renewal projects

Location	Description	Driver	Year	Comments/alternatives
Puha Substation	Transformer Replacement	Asset health, criticality	RY2024	Replacement of 3 single-phase units. This work was completed in early RY2024.
Te Araroa Substation	Transformer Refurbishment	Asset health, criticality	RY2025	Medium build up of rust on main tank. Multiple failures of tap-changer
Ngatapa Substation	Transformer Refurbishment	Asset health, criticality	RY2026	Oil leaks and build-up of rust, Gaskets requiring replacement
Tokomaru Bay	Transformer Refurbishment	Asset health, criticality	RY2027	Based on forecast health deterioration.

11.10.10 Expenditure Forecasts

The forecast expenditure for the power transformer fleet is shown in Table 105.

Capex has been forecast based on the level of replacements forecast in Table 104. As noted in Table 100, the actual project selection is based on the engineering analysis of the most current inspection, test and reliability data.

Table 105: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Transformer refurbishment	ARR	172	-	192	171	171
Wairoa tap-changer replacement	ARR	-	-	47	-	47
Total		**172**	**-**	**238**	**171**	**218**

Note: Constant 2023 $000.

[111] This includes both planned and unplanned replacements.

Forecasts for zone substation fault repair, inspection and maintenance are included within the network opex forecasts contained in Section 14.

11.11 Zone Substation Switchgear Fleet Plan

11.11.1 Changes in this AMP

The fleet has transitioned to the DNO Methodology for current and forecast asset health and renewals. Health forecasts are based on the most recent inspection (with 58% of the fleet now being inspected to the new DNO standard).

11.11.2 Fleet Overview

The zone substation switchgear fleet provides the operational protection function for the power transformers, feeders, and bus connections. The fleet also provides the important function of protecting downline equipment and assets by isolating electricity before significant energy is transmitted through the fault, causing significant damage.

Subtransmission circuit breakers are all mounted outside, and a programme is underway to replace all units that use oil insulation. For the distribution network, several different manufactured types are in operation. Some performance issues with some of the horizontal racked units have been identified.

External contractors carry out testing of substation circuit breakers.

We have several privately owned circuit breakers connected to the 11kV network. Firstlight holds agreements with these owners for access, and in some cases, we have remote operating capabilities. Communication with owners is carried out before any operation of this switchgear (unless in unplanned or health & safety-related situations).

11.11.3 Fleet Management Strategy

The 10-year switchgear fleet strategy is:

- Replace all assets deemed to be a material network risk within the planning period;
- Assess the asset health for all switchgear based on condition information using the DNO Methodology;
- Revise long-term forecasts based on the DNO asset health to ensure that there are no H1 assets present over the forecast period and ensure no H2 assets reach the point where they become H1;
- Replace all oil-filled switchgear with vacuum or SF6 type;
- Replace all pole-mounted substation switchgear;
- Ensure critical spares or alternate supply is available for all in-service switchgear

11.11.4 How the asset fleet is operated, monitored and maintained

Operating The Assets

These assets are operated via the control room or locally via manual switching. Some circuit breakers have trip coil monitoring that ensures that the trip coil circuit remains intact and operational. SCADA monitors the current and voltage flowing through the circuit breakers. Most of the circuit breakers also have the capability to be racked into both circuit earth and bus earth (RMUs excluded).

Tripping schemes provide a backup circuit breaker (usually the incomer) if a malfunction of one of the feeder circuit breakers occurs.

Monitoring The Asset (Inspection and Testing)

Table 106 summarises the circuit breaker fleet's current inspection and testing regime. The capturing of condition information is primarily time-based.

The circuit breaker inspection standards were updated during RY2021 to align with the DNO Methodology to ensure all the necessary observed condition inputs are captured.

Table 106: Circuit Breaker inspection/test programme

Asset Type	Inspection Type	Scope of Inspection	Inspection Trigger
Substation Circuit Breakers	Visual – Detailed	The following works are completed as part of the zone substation inspection programme: • Capture of observed condition inputs in relation to operation counts, oil leaks, SF6 gas levels (Sub-transmission level), and external condition. • Verification of asset attribute data.	4 monthly
	Circuit Breaker testing	• Testing of units includes trip & close time testing and insulation level measurements.	7 Yearly
	Measuring	• Thermovision	Completed in conjunction with zone substation Thermovision schedule

Maintaining The Asset

Circuit breaker maintenance is either time-based or in response to the number of fault operations. Frequent operation of the circuit breakers will accelerate the circuit breaker testing programmes.

Table 107: Circuit Breaker maintenance

Type of Maintenance	Maintenance Trigger
Defect repair	• Defects are repaired following identification following a fault, following testing or following operation of the asset. The assessment of the defect repair is made between the technician and the network engineer. Minor maintenance is performed on-site, whereas removal or replacement of the circuit breaker is required for more extensive work. • Defects are defined as remediation work on the CB that is required immediately. The scheduling of the repair is based on the risk of failure.
Planned Maintenance	Planned maintenance of these circuit breakers includes the following tasks: • Oil Replacement; • Adjustment of travel mechanisms; • Mechanism lubrication; • Number of trip operations; • Contact replacement (If required) • Cleaning, painting; • Re-insulation, replacement of damaged or worn components.

11.11.5 How asset health is assessed

The DNO Methodology is used to assess current and forecast asset health. Historical inspection records have provided sufficient data to populate most of the input requirements for the DNO methodology. The circuit breaker inspection standards were updated during RY2021 to align with the DNO Methodology to ensure all the necessary observed condition inputs are captured.

11.11.6 How renewal decisions are made on the fleet

The DNO Methodology is used to forecast asset renewal. The specific drivers for asset renewal forecasting and the triggers of specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 108.

Table 108: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/Triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no premature failures of circuit breakers within the planning period and that the risks to the health and safety of contractors are mitigated or managed SFARP. In particular: • Circuit breakers identified as material network risks are targeted to be replaced within the forecast period; • Circuit breakers identified as being in H1 are targeted for replacement within 12 months and H2 within 5 years.
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following: • The most current inspection and asset health information (with this information being verified during the project concept phase); • Evidence that the circuit breaker(s) have deteriorated to the extent that the risk of malfunction or failure is beyond the acceptable risk; • Deteriorating reliability where prime indicators are “failure to operate”, “internal faults”, or “mechanical failure”. These projects are prioritised after considering the criticality of the assets.
Defect replacement	• Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns and/or where tork of failure is assessed to be possible within the next 36 months. • Circuit breakers that are H1 are monitored and maintained at an increasing frequency above the time-based planned frequencies until replacement.

11.11.7 Fleet Performance and Risks

Current Fleet Performance

As stated in Section 11.11.1, all horizontally mounted switchgear are less reliable than the vertically racked units. To date, only one unplanned outage from these circuit breakers has been experienced, but there have been several occurrences where the horizontal units did not operate remotely.

Two premature failures of the pole-mounted switchgear at the Pehiri substation initiated the replacement of the units with new Ghorit reclosers. The other three units are in a similar condition and will likely need replacement.

Reyrolle switchgear has proved to be a reliable manufacturer for both performance and quality. To reinforce this, the capability to retrofit the units has assisted us with historical replacements.

Key Fleet Risks

The risk register has identified the following top risks in relation to substation circuit breakers (where the consequences are reliability or safety-related):

- Environment (dust and debris);
- Human interference (operating the wrong switchgear);
- Electrical and mechanical failure.

A key focus of this fleet plan is to reduce areas of elevated risk levels.

Specific risk areas which are being actively addressed are:

- Oil circuit breakers at Tokomaru Bay substation (small leaks present);
- Trip/Close failure at Kaiti & Parkinson Substations (mechanisms are filled with dust and debris).

11.11.8 Fleet Population and Age

Details on the circuit breaker populations and age profiles are shown in Table 109. The asset management implications from the age and population are that none of the circuit breakers have reached their MPL or are forecast to be replaced based on age.

However, there are other drivers for replacement (see risks above), which will see several substation switchboards and circuit breaker panels be replaced within the forecast period.

Table 109: Zone substation circuit breaker asset fleet quantity and age

Voltage	Insulation type	Population	Average age	MPL[112]	No. of circuit breakers older than MPL
Subtransmission (110/50/33kV)	Oil	1	4	50	-
	SF6	45	18	50	-
	Vacuum	2	17	50	-
Distribution Feeder (11kV)	Oil	11	40	60	-
	SF6	22	32	60	-
	Vacuum	74	19	60	-
Distribution Feeder (11kV)	Oil (pole-mounted)	7	13	45	-
Total		**162**	**22**	**55**	**-**

11.11.9 Fleet Asset Health and Forecast Maintenance and Renewal Requirements

Asset replacement and renewal forecasts

For this AMP, the asset health has been calculated using the DNO Methodology, with the results converted to the EEA Asset Indices. The current asset health for the zone substation circuit breaker fleet is shown in Figure 120, Figure 121 and Figure 122 below. The forecast health of the circuit breaker fleet is before renewals.

Figure 120: 110/50/33kV Circuit breaker asset health (outdoor)

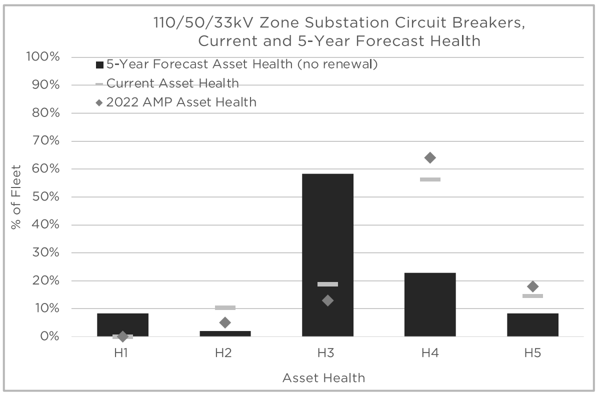
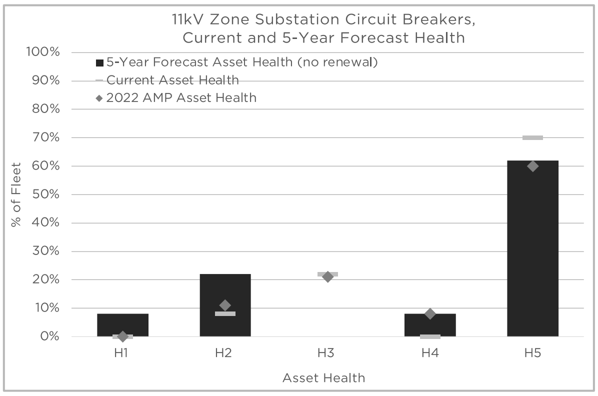
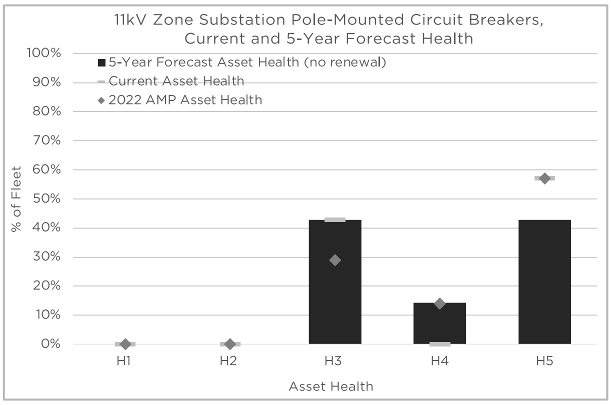


Figure 121: 11kV Circuit breaker asset health (indoor)



[112] MPL means maximum practical life. Based on the EEA health determination for circuit breaker MPL. All our subtransmission circuit breakers are outdoor, whereas the distribution circuit breakers are primarily indoor.

Figure 122: 11kV Circuit breaker asset health (pole-mounted)



The forecast health of the circuit breaker fleet is shown in Figure 120, Figure 121 and Figure 122 are based on no renewals taking place. The forecast health indicates that some replacements will be required within the forecast period.

Table 110 shows the forecast asset health and replacements over the next five years. Circuit breaker renewals are forecast to replace H1 and H2 assets within 10 years (a further 20 circuit breakers will be replaced between RY2029 and RY2030). The replacements are primarily driven by the need to increase the fleet's reliability and operate the fleet safely.

Table 110: Forecast circuit breaker replacements

Voltage	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast circuit breaker renewals over the next 5 years[113]
Subtransmission	48	5	5	2
Distribution	122	13	48	22[114]
Total	**170**	**18**	**53**	**24**

Specific asset replacement and renewal projects

The engineering analysis of the most recent condition data, reliability data, and asset criticality was used to define the priority circuit breaker replacements.

Specific 110kV circuit breaker replacements are scheduled for Tokomaru Bay substation in RY2024. 11kV circuit breaker replacements are scheduled at Tokomaru Bay, Matawhero, Kaiti, Kiwi and Parkinson substations. The final scoping of these projects will determine the schedule over the next five years.

11.11.10 Expenditure Forecasts

The forecast expenditure for the circuit breaker fleet is shown in Table 111.

Capex has been forecast based on the issues identified in the specific projects table above. The issues identified are not immediate causes for concern as the maintenance programme is sufficient to maintain the fleet in a safe and operating condition. The majority of the replacements

113 This includes both planned and unplanned replacements.
114 This includes both PM and GM zone substation circuit breakers

are programmed in the second half of the forecast period, while alternative options are being investigated for the identified issues (Tokomaru Bay substation being the exception).

Table 111: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
110/50/33kV Circuit Breaker Replacements	ARR	100	-	-	-	-
11kV Circuit Breaker Replacements	ARR, RSE	115	31	-	834	-
Total		**216**	**31**	**-**	**834**	**-**

Note: Constant 2023 $000.

Forecasts for zone substation circuit breaker fault repairs, inspection and maintenance are included within the network opex forecasts included in Section 14.

11.12 Ground Mounted Distribution Transformers

11.12.1 Changes in this AMP

The fleet has transitioned to the DNO Methodology for current and forecast asset health and renewals. Health forecasts are based on the most recent inspection (with 95% of the fleet now being inspected to the new DNO standard).

11.12.2 Fleet Overview

Distribution transformers convert the distribution voltage (11kV) to the customer voltage level (400/230V) to supply the LV system that supplies most customers.

Ground-mounted ("**GM**") distribution transformers range between 10kVA and 1,500 kVA. These are installed outdoors or inside a building/kiosk attached to precast or poured in-situ concrete pads. Installations of the GM transformers are typically located on private property for single customer installations, Firstlight owned land adjacent to road reserves, or grass berms in road reserves. In some cases, a secondary enclosure consisting of a mesh fence, concrete block wall or wood fence is used to protect the asset from external interference. Current inspection programs are looking at the practicability of some of these installations as historical installations were placed in buildings that have since been renovated and altered, making replacement and testing of the assets difficult.

11.12.3 Fleet Management Strategy

The 10-year ground-mounted distribution transformer fleet strategy is:

- Achieve 100% of all planned inspections;
- Ensure that there are no H1 assets present over the forecast period and that any H2 assets are replaced before they deteriorate to H1;
- Ensure all defects are risk-assessed and replaced before failure. The target is to have no failures of any identified defective ground-mounted transformers;
- Maintain a high standard of security and safety on all publicly accessible equipment;
- Ensure contingency spares are readily available for the different sizes of ground-mounted transformers;
- Develop a plan to deal with the ground-mounted transformers located inside buildings, where the building structure does not meet the current building code standards;
- Develop a plan to deal with the ground-mounted transformers whose ownership is disputed.

At this stage, there is no set strategy for fault rate improvement of ground-mounted distribution transformers, as the failure rate of these assets is very low.

11.12.4 How the asset fleet is operated, monitored and maintained

Operating The Assets

Operating the assets involves operating fuses and disconnectors on the LV and 11kV sides as required for planned and unplanned maintenance and fault finding. Transformer load capacity and load balance are checked using power quality analysers.

The low-voltage fuse racks inside the ground-mounted transformers can be used for isolation during planned and unplanned work on the low-voltage network. In some areas, the water heating pilot wire is controlled via a receiver located in the transformer.

Monitoring The Asset (Inspection and Testing)

Table 112 below summarises the current inspection regime for the ground-mounted distribution transformer fleet.

Firstlight is not currently monitoring the oil within the ground-mounted transformers.

Table 112: Ground Mounted Distribution Transformers Inspection/Test Program

Inspection Type	Scope of Inspection	Inspection Trigger
Visual	Capture of observed condition inputs in relation to transformers external condition, corrosion, signs of oil leakage, security (i.e. door locks/ equipment covers) and other external factors (e.g. risk to the public). Inspection and testing of ground-mounted transformers earthing. Verification of asset attribute data.	2 yearly

Ground-mounted transformer inspections are qualitative assessments undertaken by suitably qualified and competent inspectors.

Maintaining The Asset

Ground-mounted transformer maintenance typically consists of repairing defects identified through inspection, as shown in Table 113.

Table 113: Ground Mounted Distribution Transformer Maintenance

Type of Maintenance	Maintenance Trigger
Defect repair	Defects are repaired following identification from a fault or asset inspection. The assessment of the defect repair is made between the faultman and operator (in the case of a fault), and by the project manager of the assets in other cases. In cases where urgent replacement is required, shutdowns are programmed immediately for the replacement of the unit.
Minor maintenance	Minor maintenance includes painting, minor rust removal, vegetation/pest control, LV panel cleaning, and warning/danger labels replacement.

11.12.5 How asset health is assessed

The DNO Methodology is used to determine the current and forecast asset health. Inspection standards are aligned with the DNO Methodology to ensure all the necessary observed condition inputs are captured and used to inform the asset health.

11.12.6 How renewal decisions are made on the fleet

The DNO Methodology is used to forecast asset renewal. The specific drivers for asset renewal forecasting and the triggers of specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 114.

Table 114: Drivers and triggers for renewal forecasts

Renewal item	Drivers/Triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period and that H2 assets are replaced before they deteriorate to H1. Ground-mounted transformers identified as poor (H2) are targeted to be replaced within 24 months. Ground-mounted transformers assigned H3, H4 or H5 are programmed into future replacements based on the DNO modelling outcome. Other drivers for renewal are capacity upgrades and customer driven upgrades. Customer driven upgrades or installations are primarily paid for by the customer. However, instances may occur where ENL may contribute to the installation based on the book value of the existing asset. This is on a case-by-case basis, and it is the responsibility of the senior project manager to assess these instances.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or customer outages.
Refurbishment	Ground mounted transformers removed from service are evaluated to determine if it is economic to refurbish the unit. This usually

11.12.7 Fleet Performance and Risks

Current Fleet Performance

The performance of the fleet has been good. There were no faults with ground-mounted switchgear in RY2023. The historical average fault rate is 4.6 faults/1000 units/year.

Table 115 shows that the fleet is relatively young, with an average age of less than 20 years, which is the result of a high replacement rate for the asset in the last 20 years. This has led to the current good performance of the fleet.

The inspection programme has also shown that coastal proximity has a significant effect on the corrosion of the transformer enclosures/tanks.

Key Fleet Risks

Failure analysis shows that the predominant causes of in-service failure are;

- Environmental factors;
- Overloading of 400V racks (unbalanced phases);
- Bushing failure (linked to cable terminations);

Other risks identified in relation to ground-mounted transformers (where the consequences are reliability or safety-related):

- Third-party damage;
- Stability of the foundation and land;
- Public safety.

A key focus for this fleet plan is to ensure preventative maintenance triggers are identified during inspection and remediated before the risk occurs.

11.12.8 Fleet Population and Age

Details on the ground-mounted distribution transformers' population and age profile are shown in Table 115. Around 10 ground-mounted transformers will reach their MPL over the coming decade, and 2 units will reach MPL over the next 5 years.

Table 115: Ground mounted distribution transformers asset fleet quantity and age

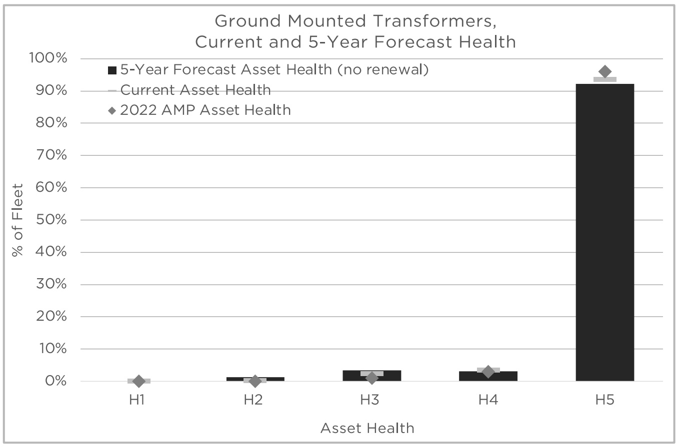
Transformer size (kVA)	Population	Average age	MPL[115]	No. of ground-mounted transformers that will reach MPL in the next 5 years
10	1	28	70	-
15	4	9.5	70	-
25	2	24.5	70	-
30	39	23.3	70	-
50	24	18.9	70	-
75	1	35.0	70	-
100	59	17.3	70	-
200	138	20.0	70	2
250	14	52.0	70	-
300	202	15.4	70	-
500	51	23.6	70	-
750	2	12.5	70	-
1000	25	26.4	70	-
1500	3	16	70	-

11.12.9 Fleet Asset Health and Forecast Maintenance and Renewal Requirements

Asset replacement and renewal forecasts

The asset health has been calculated using the DNO Methodology, with the results converted to the EEA Asset Indices. The current and forecast asset health for the ground-mounted distribution transformer fleet is shown in Figure 123. The forecast health is before any renewals.

Figure 123: Ground-mounted distribution transformer asset health



115 MPL means maximum practical life. Based on the EEA health determination for ground-mounted transformer MPL.

The forecast renewal of ground-mounted transformers is shown in Table 116. Based on current information, these forecasts are applicable to maintain the fleet's health appropriately. The forecast replacement rate is slightly lower than included in the 2021 AMP, as the current age, condition, and performance do not warrant a higher rate.

Table 116: Forecast ground-mounted distribution transformer replacements

Total population (Firstlight owned)	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast ground-mounted transformer renewals over the next 5 years
565	2	7	27

11.12.10 Expenditure Forecasts

The engineering analysis of the most recent condition data, reliability data, and asset criticality is used to define the specific replacement projects.

The forecast expenditure for the distribution transformers is shown in Table 117. As reflected in the budgets below, Firstlight sees the refurbishment of transformers of this size and quantity as inefficient and prefers to replace transformers with new assets.

Table 117: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Distribution Transformers >100kVA Replacements[116]	ARR	279	279	278	278	279

Note: Constant 2023 $000.

Forecasts for ground-mounted transformer fault repair, inspection and maintenance are included within the network opex forecasts included in Section 14.

11.13 Ground Mount Switchgear and Ring Main Units

11.13.1 Changes in this AMP

The fleet has transitioned to the DNO Methodology for current and forecast asset health and renewals. Health forecasts are based on the most recent inspection (with 80% of the fleet now being inspected to the new DNO standard).

11.13.2 Fleet Overview

This asset fleet includes ground-mounted switchgear, ring main units and distribution circuit breakers.

The ground-mounted distribution switchgear fleet is associated with the underground distribution network and provides protection, isolations, and earthing functions for the segment of the line they operate within.

Consistent with the operating context, ground-mounted switchgear is primarily installed within the higher-density areas of the network (where underground systems are more prevalent). Oil-filled units historically dominated the fleet. With the emergence of units with a smaller footprint (using SF6 insulation), replacement programmes have now superseded almost half the of the oil-filled fleet with SF6-type units.

[116] This includes ground and pole-mounted transformers. However there are very few pole-mounted transformers >100kVA

Due to the difference in footprints, Firstlight holds critical spares for the oil-insulated switchgear fleet. Replacements of oil-filled units with oil-filled units are typically done under fault situations where restoration of power to customers is a priority. Under normal circumstances, where renewal of the asset has been identified, a planned outage is scheduled, and the switchgear is replaced with the preferred SF6 insulated switchgear.

With regards to the SF6 units, several post-incident findings determined there was a manufacturing defect with switchgear manufactured between RY2000 and RY2005. A deficiency in the type of grease used resulted in the mechanical failure of units when operated. The switchgear installed between RY2000 and RY2005 has undergone corrective maintenance to remedy this fault. However, installations that occurred between RY2005 and RY2010 may still be subject to this issue and will be addressed as and when required.

The fleet age profile shows a large portion of installations occurred during the early 2000s. This resulted from earlier designs not meeting the necessary performance, safety, and reliability requirements. Future installations will primarily be SF6-filled switchgear as manufacturers have phased out the production of oil-filled switchgear.

Firstlight has a small fleet of distribution circuit breakers installed on feeders supplying the port and Gisborne city centre. Half the circuit breakers are oil-filled, and the other half are SF6. All the distribution CBS are installed indoors.

11.13.3 Fleet Management Strategy

The 10-year ground-mount switchgear fleet strategy is to:

- Capture condition information on all GM switchgear using the new DNO methodology by RY2024 and achieve 100% of all planned inspections going forward;
- Use the DNO Methodology to assess the asset health of all GM switchgear using condition information;
- Ensure that there are no H1 assets present over the forecast period, and that H2 assets are replaced before they deteriorate to H1;
- Ensure all defects are risk-assessed and replaced prior to failure. The target is to have no failures of any identified defective GM switchgear;
- Identify locations of oil-filled switchgear where replacement by gas-filled switchgear is viable. The use of criticality, reliability, and asset health information is needed to ensure that specified projects are identified for these areas;
- Improve (i.e. reduce) cable termination and fuse failure rates of GM switchgear through early detection and preventative maintenance;
- Ensure contingency spares are readily available for both oil and gas-filled switchgear;
- Keep up to date with relevant technology upgrades to benefit from the advancements that the industry provides.

Currently, the target is to reduce the switchgear fault rate through preventative maintenance on the cable terminations. In general, mechanical breakdown is rare. However, premature deterioration of the cable terminations is the main cause of failure.

11.13.4 How the asset fleet is operated, monitored and maintained

Operating The Assets

The switchgear is operated by Firstlight's approved contractors for isolation of the planned and unplanned shutdowns on the network. Installation of remotely operated ground-mounted switchgear in areas with long travel times to reduce response and restoration times is underway. These units are operated via SCADA.

Switchgear faults are normally identified through the tripping of the upstream protection device or early detection of significant damage by inspectors.

Gas switches have the capability to phase out the two incoming circuits which is an additional benefit of the replacement programme and strategy.

Monitoring The Asset (Inspection and Testing)

Table 118 summarises the current inspection and testing regime for the ground-mounted switchgear fleet. The capturing of condition information is largely time-based with more frequent inspections of older assets deemed more susceptible to failure due to age.

Table 118: GM switchgear inspection/test programme

Inspection Type	Scope of Inspection	Inspection Trigger
Visual – Detailed	Capture of observed condition inputs in relation to any signs of corrosion or rust, oil level, signs of oil leakage and any corona noise present. The observed condition inputs are consistent with the DNO Methodology for GM switchgear. Identification of any re-painting requirements and label replacements. Verification of asset attribute data. Inspection and testing of earthing connections. Inspection of terminations (where possible).	2 yearly

GM switchgear detailed inspections are qualitative assessments undertaken by suitably qualified and competent inspectors.

Maintaining The Asset

GM switchgear maintenance typically consists of defect repairs identified through inspections as shown in Table 119.

Table 119: Switchgear Maintenance

Type of Maintenance	Maintenance Trigger
Defect repair	Defects are repaired following identification of a fault or detailed switchgear inspection. The assessment of the defect repair is made between the faultman and operator (in the case of a fault), and by underground contractors in other cases. Defects are defined as remediation work on the switchgear that is required immediately. The scheduling of the repair is based on the risk of failure and the throughput time to perform the maintenance i.e. planned shutdown notification period.
Minor maintenance	Minor maintenance includes tasks such as painting, rust removal, warning label replacement and vegetation control. These tasks are typically done by the inspector.

11.13.5 How asset health is assessed

The DNO Methodology is used to determine the current and forecast asset health. Inspection standards are aligned with the DNO Methodology to ensure all the necessary observed condition inputs are captured and used to inform the asset health.

11.13.6 How renewal decisions are made on the fleet

The DNO Methodology is used to forecast asset renewal. The specific drivers for asset renewal forecasting and the triggers of specific asset renewal projects (within the overall asset renewal forecast) Table 120.

Table 120: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/Triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period, and that H2 assets are replaced before they deteriorate to H1. Switchgear identified as poor (H2) is targeted to be replaced within 1-4 Years. Switchgear assigned H3, H4 or H5 are programmed into the future replacements based on the DNO modelling outcome. For switchgear, asset health is a primary driver for renewal forecasting; other drivers that may influence renewal decisions, include the ability to replace an oil-filled switchgear with the preferred gas type, or site issues. The aim is to have all rotary switch gear removed from the network in the next 5 years and to inform customers (typically non-domestic/commercial operations) of the state of their assets where possible.
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following: • The most current inspection and asset health information (with this information being verified during the project concept phase) • Evidence that the switchgear has deteriorated to the extent that the mechanical design is susceptible to failure where the risk of failure is unacceptable • Switchgear which has demonstrated a decline in reliability performance with the reasons for unreliability being attributed to deteriorating asset condition (including oil leaks and excessive corrosion). These projects are prioritised after considering the criticality of the assets.
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 12 months. Switchgear recognised as EOL (H1) is identified with a "do not operate" tag which implies that the switchgear is inoperable and will remain in its current state. The targeted replacement of switchgear identified as H1 or inoperable is within 3 months.

11.13.7 Fleet Performance and Risks

Current Fleet Performance

The performance of ground-mounted switchgear in terms of reliability is currently acceptable. Fault events resulting from switchgear failure for RY2023 were 2.7 faults/1000 units/year. This was higher than the historical average of 0.9 faults/1000 units. As stated earlier, the causes for switchgear failure are often attributed to failure of the attachment, such as cable terminations, and not directly caused by the switchgear itself. Taking this into consideration, it is possible to state that the performance of the ground-mounted switchgear is meeting the functional expectations of the asset.

One specific issue identified with ground-mounted switchgear is the manufacturing defect stated at the beginning of this section. It refers to a defect in the grease used to lubricate the shaft of the pin that locks the switch in place. It was found that the grease had a high viscosity resulting in delayed transitions of the pin, and the switch being unable to lock into place.

No performance issues have been reported with the distribution circuit breakers.

Key Fleet Risks

The risk register has identified the following top risks in relation to switchgear (where the consequences are reliability or safety-related):

- Third-party interference;
- Cable terminations.

A key focus for this fleet plan is to ensure that, where possible, preventative maintenance triggers are identified and remediated before the risk occurs.

Specific risk areas which are being actively addressed are:

- Limited oil contingency spares (to enable replacement under fault conditions);
- Manufacturer defects associated with specific switchgear;
- Rotary switches.

11.13.8 Fleet Population and Age

Details on the switchgear population and age profile are shown in Table 121. The switchgear fleet's average age is 50% of MPL. However, due to the age profile only 8% of the fleet is due to reach MPL over the next five years.

Table 121: Ground-mounted Switchgear asset fleet quantity and age

Voltage	Population	Average age	MPL[117]	No. of units that will reach MPL over the next 5 years
Distribution Switchgear (non-RMUs)	79	26	40	14
Distribution RMUs	287	19	40	16
Distribution CBs (indoor)	15	34	60	-
Total	**381**	**21**	**41**	**30**

11.13.9 Fleet Asset Health and Forecast Maintenance and Renewal Requirements

Asset replacement and renewal forecasts (ground-mounted switchgear)

For this AMP, the asset health has been calculated using the DNO Methodology. The current and forecast asset health for the ground-mounted switchgear fleet is shown in

Figure 124 and Figure 125. There may be further changes as the remaining 20% of the switchgear is inspected.

Figure 124: Health Profile, Distribution RMUs

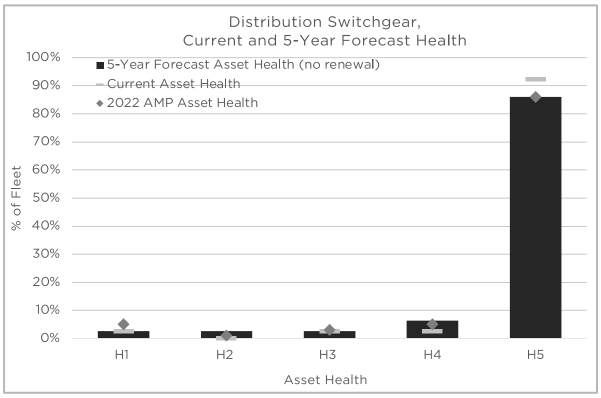
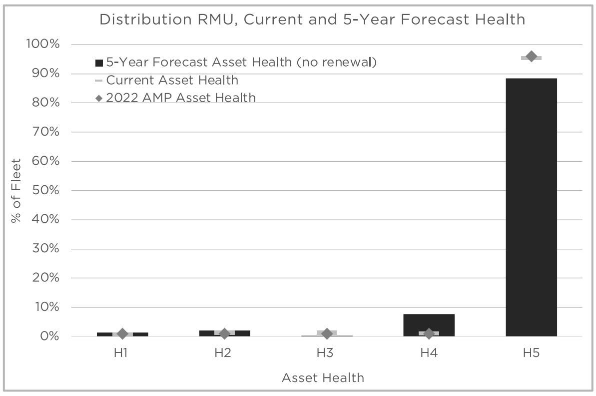


Figure 125: Health Profile, Distribution ground-mounted switchgear



117 MPL means maximum practical life. Based on the EEA health determination for ring main unit MPL.

Figure 126: Health Profile, Distribution CBs

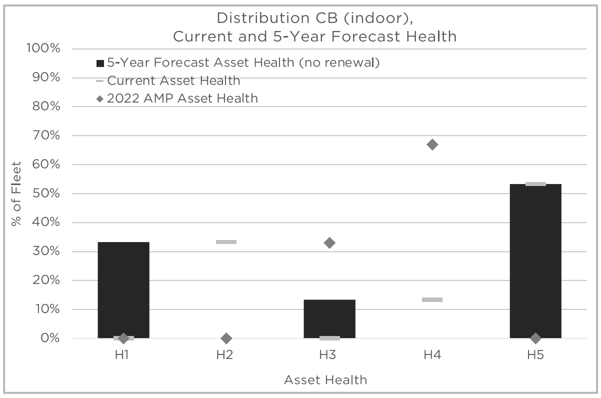


Table 122 shows the future forecast health of the ground-mounted switchgear fleet over the next five years. To align with the overall asset management strategy, switchgear units identified as H1 or H2 will be scheduled for renewal. The forecast is adequate to maintain the health of the fleet at an appropriate level to achieve the fleet asset management strategy.

Table 122: Forecast ground-mounted distribution switchgear replacements

Asset class	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast GM switchgear renewals over the next 5-years[118]
Distribution Switchgear (non-RMUs)	79	4	6	6
Distribution RMUs	287	6	10	10
Distribution CBs (indoor)	15	5	5	5
Total	**381**	**15**	**21**	**21**

Specific asset replacement and renewal projects

The engineering analysis of the most recent condition data, reliability data, and asset criticality has identified the following projects that align with reliability and efficiency targets.

These specific projects align with the fleet strategy described in Section 11.13.3

11.13.10 Expenditure Forecasts

The engineering analysis of the most recent condition data, reliability data, and asset criticality is used to define the specific replacement projects.

The forecast expenditure for the ground-mounted distribution switchgear is shown in Table 123. As reflected in the budgets below, Firstlight sees the refurbishment of transformers of this size and quantity as inefficient and prefers to replace transformers with new assets.

Table 123: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Distribution Switchgear Replacements	ARR	258	209	208	208	209

Note: Constant 2023 $000.

118 This includes both planned and unplanned replacements.

Ground-mounted distribution switchgear inspection and maintenance is included within the network opex forecasts included in Section 14.

11.14 Pole Mount Transformers

11.14.1 Changes in this AMP

For the 2023 AMP, we have updated asset health forecasting and included additional information on the fleet. There has not been any material change to the asset fleet strategy.

11.14.2 Fleet Overview

Firstlight has 3,050 pole-mounted transformers that provide the link between the distribution and low voltage networks.

The same observational measures are used to assess asset health as for ground-mounted transformers, except for the mounting mechanism.

Isolation fuses are typically located on the same pole, and failure of these units is rare. The criticality of failure of these units is low and so a "run to failure" strategy is adopted for this fleet located in rural areas. Older transformers within an outage area for other renewal work are replaced.

The cost of the asset is not significant and therefore refurbishment (replacement of broken components) of units is rare.

11.14.3 How the asset fleet is operated, monitored and maintained

The pole mount transformers have 5-yearly inspections and testing as set out in Table 124.

Table 124: Pole mount transformer inspections

Inspection Type	Scope of Inspection	Inspection Trigger
Visual – Inspection	Inspection of pole-mounted transformers is performed from the ground and observed conditions that affect the performance of the asset include: • Rust and corrosion; • Bushing condition; • Oil leaks; • Mounting stability.	5-yearly
Earth testing	Measure resistance of earthing connections	5-yearly

There is no specific planned maintenance programme for this fleet. However, remediation (be it maintenance or replacement) is undertaken in response to the inspection results or in response to faults.

11.14.4 How asset health is assessed

Pole-mounted transformer asset health is assessed using the EEA methodology. The assessment is primarily age-based.

11.14.5 How renewal decisions are made on the fleet

As mentioned above, Firstlight's strategy is to "run-to-failure", however, where an H2 transformer lies within a planned shutdown area, the unit is usually replaced (following a condition assessment). The low criticality of these assets and the current good performance of the fleet supports the replacement approach.

Pole-mounted transformers usually range from 5 – 50kVA. Growth within a region above 50kVA will either drive an installation of a second pole-mounted transformer or a change to a ground-mounted transformer. The area of growth and land availability are factors that drive this decision.

11.14.6 Fleet Performance and Risks

Current Fleet Performance

Pole-mounted transformers are a static asset in that there are no moving parts[119]. This decreases the likelihood of failure and increases asset longevity.

The reliability performance of pole-mounted transformers is currently acceptable. Pole-mounted transformer fault rate for RY2023 was 4.6 faults/1000 units/year. This was lower than the historical average of 5.0 faults/1000 units.

Key Fleet Risks

The risk register has identified the following top risks in relation to pole-mounted transformers where the consequences are reliability or safety-related:

- Lightning;
- Environmental – causing accelerated rust and corrosion;
- Third-party interference (car vs. pole).

11.14.7 Fleet Population and Age

The EEA asset health indicator guide advises that the maximum practical life for a pole-mounted transformer is 70 years. 0.4% of the fleet is forecast to reach MPL over the next five years.

Table 125: Pole-mounted distribution transformers asset fleet quantity and age

Transformer size (kVA)	Population	Average age	MPL[120]	No. of pole-mounted transformers that will reach MPL in the next 5 years
1	57	16	70	-
5	48	59	70	-
10	523	47	70	4
15	1261	28	70	5
20	79	50	70	-
25	138	52	70	1
30	626	21	70	-
50	227	27	70	2
75	2	35	70	-
100	90	24	70	-
150	1	54	70	-
200	1	57	70	-
300	3	40	70	-
-	**3,056**	**32**	**70**	**12**

The current and forecast asset health for the ground-mounted distribution transformer fleet is shown in Figure 127. The forecast health is before any renewals.

119 Can sometimes have manual tap-changer

120 MPL means maximum practical life. Based on the EEA health determination for ground-mounted transformer MPL.

Figure 127: Health profile, pole-mounted transformer

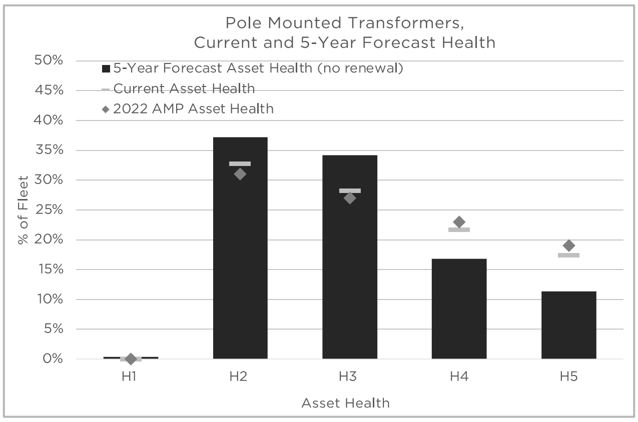


Table 126 shows the forecast renewals. The forecast includes the replacement of 120 transformers over the next five years. This replacement rate is below the forecast for H1 and H2 transformers. However, almost all of these are H2. The replacement rate is ten times the forecast H1 assets over the next five years. We expect the replacement rate to increase beyond the current forecast period.

Table 126: Forecast pole-mounted distribution transformer replacements

Asset class	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast PM transformer renewals over the next 5 years[121]
Pole-mounted transformers	3,056	1,001	1,138	120

11.14.8 Expenditure Forecasts

The engineering analysis of the most recent condition data, reliability data, and asset criticality is used to define the specific replacement projects. Forecast expenditure is based on the proposed replacement strategy of reliability and criticality and this expenditure is deemed to be sufficient for this asset.

The forecast expenditure for the pole-mounted distribution transformers is shown in Table 127. Firstlight sees the refurbishment of this size and quantity as inefficient and prefers to replace transformers with new assets.

Table 127: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Distribution Transformer Replacements	ARR	122	157	156	156	157

Note: Constant 2023 $000.

Pole-mounted distribution transformer inspection and maintenance is included within the network opex forecasts included in Section 14.

[121] This includes both planned and unplanned replacements.

11.15 Pole Mounted Reclosers, Sectionalisers, and Load Break Switches

11.15.1 Changes in this AMP

For the 2023 AMP, we have updated asset health forecasting and included additional information on the fleet. There has not been any material change to the asset fleet strategy.

11.15.2 Fleet Overview

Reclosers and sectionalisers work in conjunction with the substation protection equipment to provide a protection scheme that operates to minimise the extent of outages. Firstlight's terrain and landscape increase the difficulty in providing communication signals to some areas of the network and can limit where this equipment is installed.

As part of the asset management strategy, analysis of unplanned outage areas is undertaken to identify where additional sites may be best utilised. Currently planning to install 8 new sites over the next two years (a mixture of reclosers and circuit breakers), which will further segment the network and decrease the effect of outages on the associated feeders.

Due to the terrain, communication links to remote sites are not always reliable. Therefore manual operation capability is mounted on most of the units to ensure operation of the sites is possible both locally and remotely.

11.15.3 How the asset fleet is operated, monitored and maintained

Remote-controlled switches are monitored via the control room. Communication modules attached to each control box allow for remote opening/closing functionality as a minimum (typically for remote load break switches). Reclosers typically have additional functions that assist control room operators with determining the type of fault or network disturbance.

These assets are subject to a time-based inspection regime (which is bi-annually for reclosers and sectionalisers, and 5-yearly for air-break switches). Functional testing is also performed when the assets are commissioned. Any earthing associated with the asset is tested every 5 years.

11.15.4 How renewal decisions are made on the fleet

There are three different criteria that drive replacements for this asset fleet which include:

- Renewal of existing assets based on health and age;
- Renewal of assets based on key fleet risks;
- Installation of new assets in line with Firstlight's operating strategy.

11.15.5 Fleet Performance and Risks

More faults due to communications, protection relays (contact burnout), and flat batteries are more common than the breakdown of the units themselves. The EEA guidelines are used as a guide for age replacements and the bulk of the fleet still has upwards of 10 years of life remaining.

The risk register has identified the following top risks in relation to automation equipment (where the consequences are reliability or safety related):

- Asset damage due to faulty operation;
- Contact connection burnout causing phase to unbalance;
- Mechanical breakdown (contact breakdown and insulation failure);
- Environmental factors (lightning, rust and corrosion);
- Wildlife or insects (interfering with the control box).

11.15.6 Fleet Forecast Asset Health and Renewals

Firstlight uses the EEA health guide to determine the health of the assets. The recommended MPL for reclosers and remote switches is 45 years. The associated hardware to operate the equipment (radios and RTUs) will typically be replaced once before the end-of-life period of the switch. Batteries used to supply the relay, switch and communication equipment are typically replaced every four years.

The current and forecast asset health for the pole-mounted recloser and sectionaliser fleet is shown in Figure 128. The forecast health is before any renewals.

Figure 128: Health Profile – Pole-Mounted Reclosers, Sectionalisers and Load-Break Switches

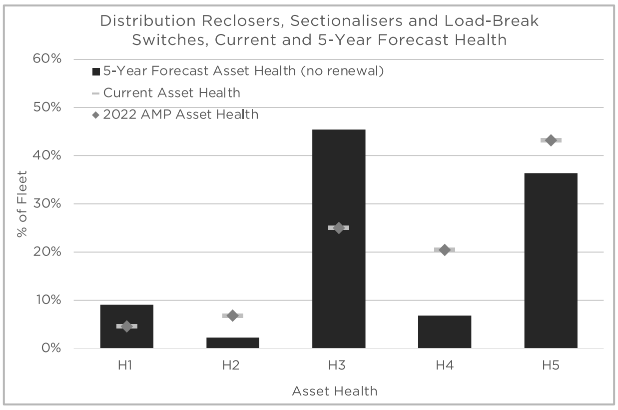


Table 128 shows the forecast renewals. The forecast includes the replacement of 10 reclosers and sectionalisers over the next ten years. This replacement rate is above the forecast H1 and H2 assets. The current forecast expenditure will address the key fleet risks and remove legacy equipment.

Table 128: Forecast Pole-Mounted Reclosers, Sectionalisers and Load-Break Switches Replacements

Asset class	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028), before renewal	Forecast PM switchgear renewals over next 5-years[122]
Pole-mounted reclosers, sectionalisers and load-break switches	44	5	5	10

11.15.7 Expenditure Forecasts

The engineering analysis of the most recent condition data, reliability data, and asset criticality is used to define the specific replacement projects. Forecast expenditure is based on the proposed replacement strategy of reliability and criticality and this expenditure is deemed to be sufficient for this asset.

The forecast expenditure for the pole-mounted reclosers and sectionalisers is shown in Table 127.

Table 129: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Pole-mounted reclosers and sectionalisers replacement	ARR	42	42	42	42	42

Note: Constant 2023 $000.

122 This includes both planned and unplanned replacements.

Forecasts for pole-mounted reclosers, sectionalisers and load-break switches fault repair, inspection and maintenance are included within the network opex forecasts included in Section 14.

11.16 Overhead Switchgear (fuses, links, air-break switches, earth switches)

11.16.1 Changes in this AMP

For the 2023 AMP, we have updated asset health forecasting and included additional information on the fleet. There has not been any material change to the asset fleet strategy.

11.16.2 Fleet Overview

Overhead switchgear provides the operating mechanisms to sectionalise the network into small areas. Overhead fuses are used to form the protection function between customers or privately owned assets and network assets. They also provide an inexpensive alternative to installing reclosers and more expensive protection devices.

Protection settings of reclosers must consider these fuses and work with them to provide a protection scheme that minimises outage areas.

These assets also provide the visible gap between a live network and a de-energised network so that planned maintenance and replacements on a network can be completed.

The fleet consists of 3,939 protection fuses, 623 air/load break switches and 90 links.

11.16.3 Asset Management Strategy

From an asset strategy perspective, the objectives for the overhead switchgear are to:

- Develop a condition-based asset health forecasting methodology;
- Install in strategic locations to isolate faults without overpopulating;
- Achieve a high standard of operational reliability;
- Minimise maintenance costs, relying on a replacement response to keep costs low.

11.16.4 How the asset fleet is operated, monitored and maintained

These assets are manually operated by qualified staff including linemen and faultmen. Protection fuses operate when they detect a fault and network staff are usually notified by the faults centre who take the calls from customers on the network. There is no remote monitoring of this equipment, however, pole inspection programmes will usually identify any obvious flaws with the equipment attached to the pole.

Switches installed within substations are maintained more frequently than field assets as they are more critical to the operation of the network.

Maintenance is carried out on air-break switches and earth switches within substations. Obvious issues found on field assets are treated as defects and a shutdown or replacement is planned. Maintenance includes:

- Contact alignment;
- Greasing of contacts and nipples;
- Earthing braid and conductor replacement.

Equipment found to be defective is maintained in accordance with the manufacturer's specifications. Maintenance costs for these assets are included within 'other asset' categories (i.e. zone substations, rural automation maintenance etc.).

11.16.5 How renewal decisions are made on the fleet

Renewals for this fleet are primarily based on asset type (see asset risk section) and health. It is difficult to determine the condition of these assets using visual inspections and the condition of these assets is often unknown until they are operated.

11.16.6 Fleet Performance and Risks

Current Fleet Performance

The reliability performance of pole-mounted switchgear is currently acceptable. Pole-mounted switchgear fault rate for RY2023 was 4.8 faults/1000 units/year. This was only marginally higher than the historical average of 4.3 faults/1000 units. We suspect the extreme weather events in RY2023 influenced the failure rate. The causes of the failures range from blown jumpers to the misalignment of contacts.

Key Fleet Risks

The risk register has identified the following top risks in relation to overhead switchgear (where the consequences are reliability or safety-related):

- Breakdown of fuse sleeves;
- Contacts burning;
- Mechanism wear and tear;
- Bearing stiffness or jamming;
- Insulator failure.

Table 130 describes the specific risk areas or type issues that are being actively addressed.

Table 130: Specific overhead switchgear risks

Risk	Mitigation
Quadrant ABS – Built with a wire operating system and has been identified as being problematic should the wires break during operation.	Replacement programme of 10 units per annum.
ABS insulator failures – Firstlight has noted a trend in insulator failures on ABSs purchased from the supplier in the early 2000's. Discussions with other EDBs have noted that this is an industry wide problem.	Stock sufficient replacement units.
Glass Type fuses – Operation requires high degree of skill and poor operation can lead to arcing. Fuse type and holders are no longer in production and spares are currently being used from the replacement units.	Replacement programme of 30 units per annum.

11.16.7 Fleet Population and Age

The EEA asset health indicator guide advises that the maximum practical life for a pole-mounted switchgear is 45 years. 16% of the fleet is forecast to reach MPL over the next five years.

Table 131: Pole-mounted distribution switchgear asset fleet quantity and age

Switch type	Population	Average age	MPL[123]	No. of pole-mounted switchgear that will reach MPL in the next 5 years
Fuse	1,112	21	45	143
Transformer fuse	2,827	25	45	553
Link	90	14	45	4

[123] MPL means maximum practical life. Based on the EEA health determination for ground-mounted transformer MPL.

Switch type	Population	Average age	MPL[123]	No. of pole-mounted switchgear that will reach MPL in the next 5 years
Air-break switch	623	25	45	135
	4,652	**24**	**48**	**835**

11.16.8 Forecast Asset Health and Renewals

The current and forecast asset health for the pole-mounted fuse and switch fleet is shown in Figure 129 to Figure 132. The forecast health is before any renewals. These forecasts are currently age-based. Given the results of recent line inspections (which aren't used for health forecasting for this fleet) and the current fault rate, we believe the low-health assets are overstated. Utilising condition data will be a focus over the coming year.

Figure 129: Health profile, air break switches

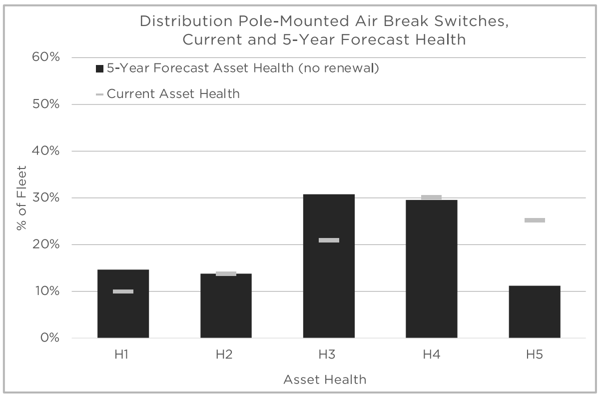


Figure 130: Health Profile, OH Fuses

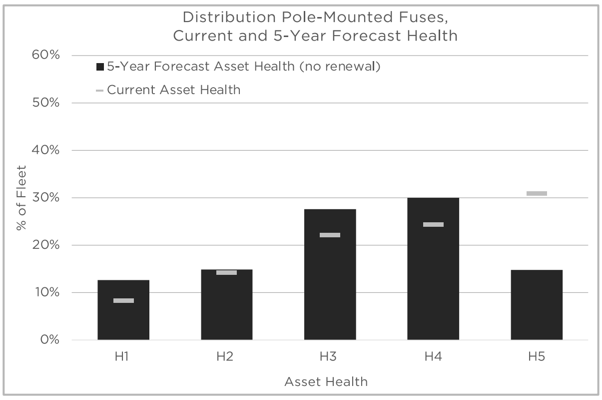


Figure 131: Health Profile, OH Transformer Fuses

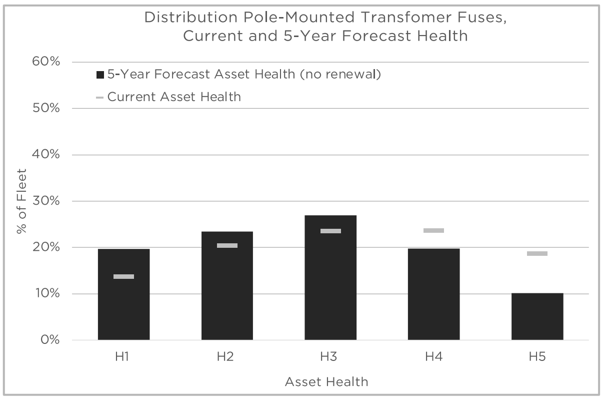


Figure 132: Health Profile – OH Links

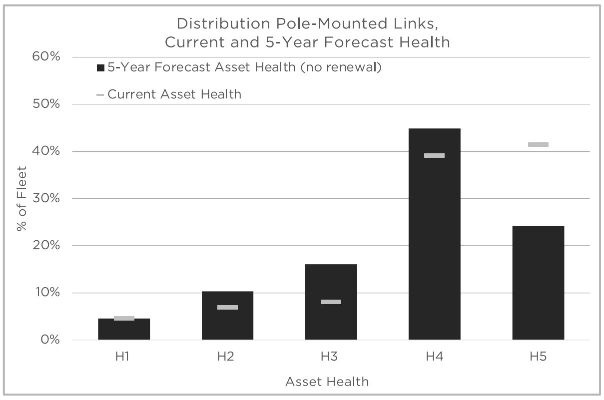


Table 133 shows the forecast renewals. The forecast includes the proactive replacement of fuses and switches, and also the replacement of fuses when pole-mounted transformers are renewed. The replacement rate is consistent with our view of the fleet's health. However, the fleet is aging and we expect the renewal rate will increase beyond RY2028.

Table 132: Forecast Pole-Mounted Fuses and Switches Replacements

Asset class	Total population	Grade H1 & H2 assets (2023)	Forecast grade H1 & H2 assets (2028) before renewal	Forecast PM switchgear renewals over the next 5years[124]
Distribution switches and fuses (pole-mounted) replacements	4,652	522	755	200
Distribution fuse replacements (when pole-mounted transformer replaced)	-	-	-	120
Total	**4,652**	**522**	**755**	**320**

11.16.9 Expenditure Forecasts

The engineering analysis of the most recent condition data, reliability data, and asset criticality is used to define the specific replacement projects. The forecast expenditure for the pole-mounted switches and fuses is shown in Table 127.[125]

Table 133: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Distribution switches and fuses (pole-mounted) replacement	ARR	163	163	162	163	163

Note: Constant 2023 $000.

Forecasts for pole-mounted switch and fuse fault repair, inspection and maintenance are included within the network opex forecasts included in Section 14.

11.17 Zone Substations

11.17.1 Fleet Overview

Zone substations are positioned throughout the region, and some are placed within residential and commercial areas. These substations require additional security and earthing to ensure that the safety of the public is not compromised. In addition to the regulatory requirements and best practice designs for substation safety, sites are audited annually by an external auditor who surveys the sites and ensures that safety equipment (safety fences, earthing straps etc.) is fit for purpose.

Currently there are 21 zone substations on the network with 70% located in the Gisborne region. This section (zone substations) includes the building, grounds, security and any other non-operational asset contained within the compound.

Demand growth within the Gisborne region has been relatively low. However, evaluations of network load and line voltage limitation is driving the consideration of other options that will enable the current substations to operate within applicable security levels.

11.17.2 How the asset fleet is operated, monitored and maintained

Inspection and maintenance of zone substations is a critical task for Firstlight. As well as maintaining operational performance, it is essential that all public safety risks are mitigated so far as is reasonably practicable.

[124] This includes both planned and unplanned replacements.
[125] This excludes fuses replace when pole-mounted transformers are replaced.

Regular (4 monthly) inspections of substations are performed predominantly to confirm the security of the substations (i.e. the fencing is secure and access to the public is restricted). All substation equipment is inspected, and any irregularities or issues are notified. Five-yearly earth testing is also undertaken.

External contractors are engaged to keep the sites clean and tidy.

11.17.3 How renewal decisions are made on the fleet

The renewal of zone substation buildings is based on the condition of the buildings and compliance requirements. Other equipment, such as fencing, is replaced when maintenance becomes uneconomic or in response to an increase in public safety risk. From an asset health perspective, the above-mentioned criteria typically result in no H1 assets being present and H2 assets being replaced before they deteriorate to H1.

11.17.4 Fleet Performance and Risks

Current Fleet Performance

A proactive approach to maintaining zone substations is taken. All zone substation buildings are in reasonable condition (except for the Puha substation mentioned below).

Key Fleet Risks

The risk register has identified the following top risks in relation to zone substations (where the consequences are reliability or safety-related):

- Wildlife (sub fencing);
- Public access;
- Noise.

In terms of specific risk areas which are being actively addressed:

Table 134: Specific substation risks

Active Risk	Mitigation
Puha substation asbestos	Replace roof and dispose of existing roof as required.
Carnarvon substation earthquake rating	Carry out requirements noted in engineer's report
Gisborne substation earthquake rating	Carry out requirements noted in engineer's report
Wairoa substation earthquake rating	Carry out requirements noted in engineer's report

11.17.5 Fleet Population and Age

Zone substations were installed between 1971 and 2019. Presently there are two substations with a H2 rating. The remaining substations have asset health ratings between H3 and H5, with most being H3.

11.17.6 Expenditure Forecasts

The forecast expenditure on zone substations is shown in Table 135. This comprises a range of specific projects and programs to maintain the asset fleet.

Table 135: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Battery replacements	ARR	23	70	39	85	39
Local service, CTs and VTs replacement	ARR, RSE	157	35	219	53	207

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Building and security fencing refurbishment and replacement	ARR, RSE	44	83	285	107	108
Cable replacements	ARR	84	83	178	83	84
Earthing and Switchyard refurbishment	ARR	38	125	93	-	-
Secondary electrical equipment replacement	ARR	22	26	26	-	-
Total		**367**	**424**	**839**	**329**	**437**

Note: Constant 2023 $000.

Opex forecast covers the routine inspection, maintenance, and corrective asset replacements. An allowance for unplanned work has been made based on historical expenditure levels. Routine and corrective maintenance includes the expenditure for quarterly inspections of all zone substations, grounds maintenance of the yards, which include weed spraying, lawn maintenance, and building upkeep. It also includes repairs or maintenance to the zone substation equipment, transformer maintenance, oil sampling (DGA's) and thermal imaging of high voltage equipment (to check for hotspots). The work is included in the network opex forecasts included in Section 14.

11.18 Protection Relays

11.18.1 Fleet Overview

Protection relays detect disturbances in the voltage and current flowing through the circuits. When set parameters are breached, the relay signals the circuit breaker to trip, which subsequently breaks the flow of electricity. Newer digital relays now have the capability to calculate other parameters (kW, power factor, etc.) which operators and engineers use to assist them with loading and other technical measurements. The communication network now directly links (via IP or fibre) to the relays remotely and provides engineers with live and historical data.

In terms of relay replacements, the strategy has been to replace protection devices that have internal faults or to update the fleet to enable technology advances and functionality progression.

Several substations and switchgear sites still have electromechanical or Mikrotrip relays that have been flagged for replacement. Scheduled replacements of these units will be aligned with the replacement of the associated primary equipment (circuit breakers and substation layout).

There is SCADA monitoring of some relays to enable alarming of relay process errors. This enables testing of a relay when required.

This fleet also includes the relay protection devices attached to pole-mounted reclosers and sectionalisers, and remote switches.

11.18.2 How the asset fleet is operated, monitored and maintained

Firstlight holds in-house engineering capabilities to develop its own protection schemes and settings for devices on the distribution network and most of the subtransmission network. Protection schemes that require extensive review and are critical to the network operation (such as the 110kV subtransmission network and interconnections with Transpower's Tuai switchboard) are contracted to external engineering companies for review to ensure that critical protection schemes operate correctly.

These assets are inspected visually (as part of the substation or recloser inspection cycles), and functional testing is undertaken every five years for electromechanical relays and seven years for digital relays. Automatic under-frequency relays are tested every four years as required by the electricity industry participation code.

Battery replacement occurs as required.

11.18.3 How renewal decisions are made on the fleet

Replacements for this fleet are primarily driven by relay type issues, technological advances and age. Condition assessments are challenging; however, regular functional testing of the relays ensures they are operating within their programmed settings.

Engineering access to most of the substation relays has been established, with the remaining relays due to be replaced in line with a substation or associated primary equipment upgrade.

For rural automated switchgear sites, the relays normally last longer than the associated pole-mounted switches. In these situations, the replacement of the relays is driven by an upgrade of the switch and to increase the network sensitivity to events such as earth fault and overcurrent pickups.

11.18.4 Fleet Population and Age

Replacements to date have kept the relay ages and health within acceptable limits. Kiwi substation is the only substation that has electromechanical relays (and is identified as H1 assets). These relays were maintained and tested in 2018 and found to be operating efficiently and will be tested every four years until replacement.

11.18.5 Fleet Performance and Risks

Current Fleet Performance

As a critical asset to protection schemes, Firstlight maintains and inspects these assets frequently. The performance of this fleet has been good.

The TEAMS application enables the monitoring of relays remotely and graph/logs events on the relays. This software forms part of the vegetation strategy to analyse earth fault and overcurrent pickups on feeders. This will assist the vegetation team in targeting areas for vegetation inspection and pruning to minimise the effect vegetation is having on the network.

Key Fleet Risks

The risk register has identified the following top risks in relation to protection relays (where the consequences are reliability or safety related):

- Age of electromechanical relays;
- Relay malfunction or setting error – extending the period where damage to the network can occur;
- Relay type;
- Lightning strikes (relays on pole-mounted enclosures).

In terms of specific risk areas which are being actively addressed:

Table 136: Specific fleet risks

Active Risk	Mitigation
Electromechanical relays at Kiwi substation	Relays due to be replaced within the forecast period (in line with switchgear replacement)

11.18.6 Expenditure Forecasts

There are no specific projects for this asset type. Forecast expenditure is projected to be based on natural replacement frequencies and the replacement of old electromechanical relays. Kiwi substation replacements will fall under the switchgear project budget (refer to the substation switchgear fleet plan, Section 11.11).

Table 137: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Protection relay replacements	ARR	173	172	-	-	-

Note: Constant 2023 $000.

11.19 SCADA (Supervisory Control and Data Acquisition)

11.19.1 Fleet Overview

Firstlight's SCADA master station is located at the head office in Carnarvon St and comprises an Abbey system dual master / backup configuration. The current master station was installed in 1999 (and has undergone regular updates). The SCADA system is used for real-time monitoring and control of the network. Frequency, voltage, current and temperature information is obtained from remote sites and stored at 30-minute intervals.

This information is used to report load trends for planning and to alert operations staff of abnormal conditions.

Since the initial installation, regular upgrades have been made to the master station and software has been updated to improve functionality.

There are 16 Abbey system full RTUs located at each of Firstlight's major substations and 168 Abbey systems Topcat at remote control switches or monitoring and control sites.

11.19.2 Asset Management Strategy

From an asset strategy perspective, the objectives for the SCADA assets are to:

- Minimise operational delays by implementing systems that effectively pass on information in a timely manner;
- Provide systems designed with the flexibility to support emerging technology;
- Ensure contingency spares are maintained;
- Deal promptly with any known defect;
- Target asset renewals to maintain performance.

As part of the resilience drive, a second master station at the Massey substation has been installed.

11.19.3 How the asset fleet is operated, monitored and maintained

The RTU input and output functions are tested in conjunction with maintenance of the associated equipment. During protection and switchgear testing, the digital indications, analogues, measurements and control functions are verified back to the master station. General indications such as door security and fire alarms are verified during zone substation visual inspections.

Monitoring of the assets and SCADA equipment is reliant on the communications network being functional. This dependency has been reflected in the investment in dual communication options described in the communications fleet plan.

Defects are repaired when these are identified.

11.19.4 How renewal decisions are made on the fleet

RTU renewals are based on technological advances and age. There is no set programme to replace RTUs as the units are replaced after failure. Topcat (series 1) RTUs have been phased out by the supplier and any in-service units that break down are replaced with Topcat (series 2) RTUs.

The Abbey system was purchased in 1999 and systems like this typically have an expected life of 15 years. As systems age, support becomes more expensive and replacement technology becomes more attractive.

The PCs used in the master station are targeted for renewal every 5 years.

11.19.5 Fleet Performance and Risks

Current Fleet Performance

The Topcat (series 1) units are progressively replaced as real-time alarm indicates CPU or main board issues at around 16 years. Replacement units have IP or analogue communications options and improved signal clarity.

All original substation communication units have been replaced to overcome lockup issues following master station communication restarts and to take advantage of new communications options.

Key Fleet Risks

The risk registers have identified the following top risks in relation to the SCADA system (where the consequences are reliability or safety related):

- Communication failure;
- Lightning strikes (which account for a few in-service failures at rural automation sites);
- Pest infestation e.g. ants cause circuit board and socket interface failures;
- Ageing components on the circuit board.

Specific risk areas which are being actively addressed:

- SCADA's heavy reliance on communications creates a risk should the communications network fail. Where possible two communication routes for key sites have been provided in addition to both IP and radio communication pathways to substations.

11.19.6 Expenditure Forecasts

The SCADA system is planned for a significant upgrade and enhancement. This is described in the development section (refer to Section 10). In-house engineering capabilities are retained to programme, maintain and upgrade systems. Rural development expenditure is in response to the new rural automation sites planned in the forecast period and will be used to purchase the SCADA equipment associated with developing these sites.

Table 138: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
SCADA and RTU replacements	ARR	27	27	27	27	27

Note: Constant 2023 $000.

Forecasts for fault repairs, inspection and maintenance activities are included within the network opex forecasts included in Section 14.

11.19.7 SCADA Switching and Outage Management System

Firstlight is planning to install a SCADA switching and Outage Management system. These systems, also referred to as ADMS (Advanced Distribution Management System), are a software solution to monitor, control, and optimize the distribution network. The system integrates real-time data from various sources, such as sensors and devices across the power grid, enabling operators to remotely manage the flow of electricity, identify faults, and respond to outages promptly.

The SCADA component helps monitor operational status and make informed decisions about switching operations to balance load and prevent disruptions. The Outage Management component assists in detecting and locating faults, streamlining outage restoration processes, and enhancing overall grid reliability and customer service. Adopting an ADMS system will be a vital part of modernising Firstlight's network to improve efficiency and resilience.

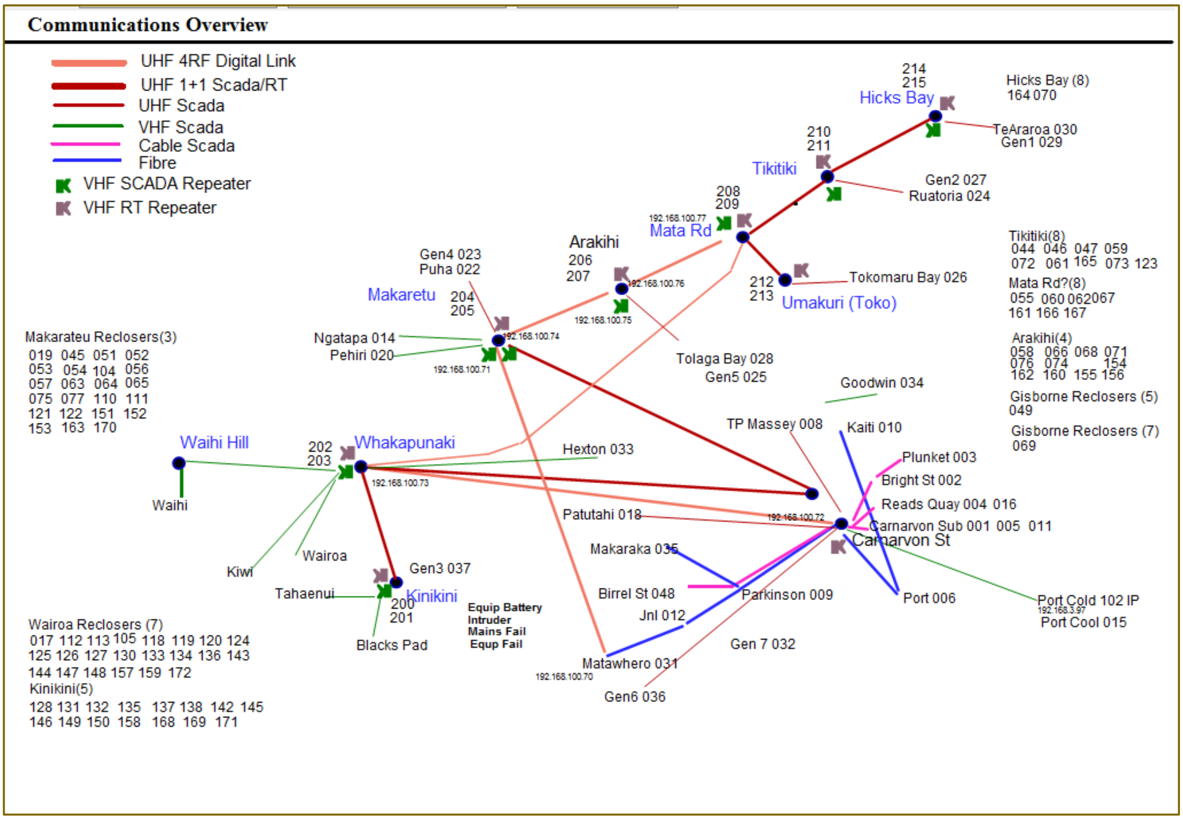
11.20 Communication System

11.20.1 Fleet Overview

Multiple communications media and protocols are used to provide voice and data information for the operation of the network. Systems include VHF radio, UHF radio, copper cables, and fibre cables. Data communication is via IP, RS232/485/422 serial and audio. Protocols associated with data communication include Modbus, DNP3, and Abbey Systems (HTLC).

In 2015, all voice SCADA was switched from analogue to digital communications. This was due to the repeater technology becoming redundant. It also increased capabilities and health and safety as it had the added benefits of GPS and signal clarity.

Figure 133: Firstlight's Communication Overview



Diesel generators are situated at the radio huts and have automatic start up functionality in case of power outages.

It is planned to relocate the Arakihi radio site as the 11kV line supplying the site is 5km long and runs through a long forestry corridor, which is causing supply reliability issues to the site.

Firstlight has 11 standby generators which are used to maintain network operability during power outages.

11.20.2 Asset Management Strategy

From an asset strategy perspective, the objectives for the communications assets are to:

- Minimise operational delays by implementing systems that effectively relay information in a timely manner;
- Provide systems designed with the flexibility to support emerging technology;
- Ensure the contingency spares are maintained;
- Deal promptly with any known defect;
- Target asset renewals to remove obsolete assets.

11.20.3 How the asset fleet is operated, monitored and maintained

The communications network allows the monitoring of all remote assets. Mikrotik routers are used to communicate via IP and 'The DUDE' software to monitor the network remotely. This software improves the management of the network environment and allows for real-time monitoring of all IP and fibre sites. Eight radio sites throughout the region contain and house the communications equipment.

Inspection of these huts is completed annually, and access tracks are maintained as some are located on hilltops to maximise coverage and signal clarity.

There is some monitoring of the radio systems in place to provide early warning of equipment malfunction. Annual testing and calibration is carried out to ensure the equipment's performance is within specification.

Defects with the voice radio are treated as critical as operational staff rely on clear communication with the control room for switching instructions.

11.20.4 How renewal decisions are made on the fleet

Renewal of equipment such as radios is based on technology advancements or asset failure.

11.20.5 Fleet Performance and Risks

Current Fleet Performance

The SCADA system monitors the communications network performance to all remote sites. Operations staff monitor the communication network performance and send technical staff to fix any issues.

Key Fleet Risks

Key risks associated with the communications network are loss of voice network while operating. The operating and maintenance regime exists to keep this risk as low as reasonably practicable.

11.20.6 Expenditure Forecasts

The capex forecast for the communications fleet is shown in Table 139. The higher capex in RY2025 and RY2028 are for site generator replacements.

Table 139: Forecast Capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
SCADA and RTU replacements	ARR	54	100	64	64	100

Note: Constant 2023 $000.

Forecasts for fault repairs, inspection and maintenance activities are included within the network opex forecasts included in Section 14.

11.21 Other network assets

Expenditure forecasts associated with other network assets are shown in Table 140.

Note: $000 (in March 2023 constant prices)

Table 140: Forecast capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Project - Lock Upgrade	ARR	139	139	138	-	-
LV Disconnection box replacements	ARR	16	16	16	16	16
LV Pillar box replacements	ARR	80	57	57	57	57
Service pillar replacements	ARR	31	63	62	63	63
Replace failed ripple relays	ARR	12	11	11	11	11
Galv Meter Box (Asbestos) replacements	RSE	31	31	31	-	-
Galv Meter Box replacements, Wairoa	RSE	-	104	104	104	105
Total		**309**	**422**	**421**	**251**	**252**

Note: Constant 2023 $000.

11.22 Generation

11.22.1 Fleet Overview

The generation portfolio consists of diesel generators embedded at zone substations, truck-mounted units and trailer-mounted units, and small standby generators at critical communication sites.

The generators generally comprise an engine, alternator, SCADA (control systems for remote management), and building (housing components, typically constructed from shipping containers with additional egress points for the large generator fleet).

The generators provide security of supply support, voltage support and maintain the distribution network during planned and unplanned outages. Following recent weather events, there is increased community recognition for the deployment and the value of generation to support essential services.

The diesel generators embedded at zone substations can also manage short-term constraints during peak load.

The generator fleet accounts for less than 2% of the overall assets by value but has high operational costs (fuel, maintenance and compliance), requiring significant management of these assets to maintain their availability.

The generators used for system security support have reached or exceeded their maximum life (MPL assessed as 20 years) and require refurbishment or replacement.

The larger generators used for system security are described in Table 141.

Table 141: Fixed and Truck-mounted Generators

Site	Description
Te Araroa	• One 1 MVA generator operating at 11 kV embedded at the substation • Perkins engine, 4012 series, Stamford alternator and 400/11kV transformer, 5,000 litres fuel • 2 x 20' container
Ruatoria	• One 1 MVA generator operating at 11 kV embedded at the substation • Perkins engine, 4012 series, Stamford alternator and 400/11kV transformer, 5,000 litres fuel • 1 x 40' container
Tolaga Bay	• One 1 MVA generator operating at 11 kV embedded at the substation • Perkins engine, 4012 series, Stamford alternator and 400/11kV transformer, 5,000 litres fuel • 2 x 20' container
Puha	• One 1 MVA generator operating at 11 kV embedded at the substation • Perkins engine, 4012 series, Stamford alternator and 400/11kV transformer, 5,000 litres fuel • 2 x 20' container
Mahia	• One 1 MVA generator operating at 11 kV is located in berm area. Connected to 11 kV feeder (3301 Mahia) • Perkins engine, 4012 series, Stamford alternator and 400/11kV transformer, 5,000 litres fuel • 1 x 40' container
Carnarvon Street	• One 1 MVA generator (refurbished) • Cat engine, C32 series, Stamford alternator, 400/11 kV transformer, 5,000 litres fuel • 1 x 40' container
Truck-mounted (at Carnarvon St, Gisborne)	• Truck-mounted 300 kVA generator and associated truck-mounted 200 kVA transformer 400 V or 11 kV (3 phase) to distribution network

The trailer-mounted generators used for planned and unplanned outage support are shown in Table 142.

Table 142: Trailer-mounted Generators

Site	Description
Carnarvon St, Gisborne (Trailer-mounted)	• 1 x 15 kVA (400 volts) single-phase, three-phase selectable • 1 x 65 kVA (400 volts) three-phase • 1 x 88 kVA (400 volts) three-phase • 1 x 110 kVA (400 volts) three-phase
King St, Wairoa (Trailer-mounted)	• 1 x 65 kVA (400 volts) three-phase

Firstlight maintains a fleet of generators dedicated to critical sites. These assets provide low-voltage supply to network locations where continuity of supply is required (refer to Table 143(.

Table 143: Critical-site Generators

Site function	Description
Communication, depot backup supply	• 11 x single phase diesel< 15 kVAe

11.22.2 Fleet management strategy

The 1.0 MVAe generator fleet was historically managed by Eastland Generation (a wholly owned subsidiary of Eastland Group) and subject to their asset management strategy. With the acquisition of Eastland Network by Firstgas Group, these assets were transferred to Firstlight.

Our 10-year generator fleet strategy is to:

- Ensure there are no H1 assets present over the forecast period;
- Actively monitor health to prevent/minimise premature failure;
- Standardise design to create interchangeable assets for all replacements;
- Develop and complete maintenance programs consistent with the manufacturer's guidelines and standards to ensure assets are kept in a reliable condition;
- Ensure asset sizing is consistent with forecast load growth.

11.22.3 How we operate, monitor, and maintain the assets

Operating the assets

The smaller generators are operated manually during planned or unplanned outages. The large generators are automatically connected and synchronised with the network during peak load conditions or when supply is lost. When generators are used in a loss of supply, they must be disconnected to electricity is restored to prevent synchronising issues.

Monitoring (inspection and testing) the asset

Real-time monitoring of key parameters (via SCADA) provides triggers for routine maintenance activities and planned preventative maintenance.

Faults on generators can occur on any of the key components and can vary in criticality. Technicians are dispatched to the site to investigate the cause of a fault should monitoring equipment be unable to provide adequate information.

Table 144 summarises our current inspection and testing regime for the fleet. Observed condition information is captured through four-monthly inspections and measurement-based condition information.

The inspection standards are being updated to align with the DNO Methodology to ensure all the necessary observed and measured condition inputs were captured.

Visual inspections are performed by specialist Contractors and personnel for the appropriate component classes. Health information is updated based on the outcomes of the inspections.

Table 144: Inspection/test program

Asset	Inspection type	Scope of inspection	Inspection trigger
Generator	Visual – Inspection	Routine inspection to check for oil leaks, rust and corrosion, Oil level, coolant and lubrication	To be developed
	Measurement	Hours run	To be developed
	Measurement	Maximum load	To be developed

Maintaining the asset

Maintenance typically consists of work associated with the moving components. Planned maintenance is based on the manufacturer's specifications and specialist Contractor's recommendations following assessments.

Table 145: Maintenance

Type of maintenance	Maintenance trigger
Defect repair	Defects are repaired following identification following a fault or inspection. The assessment of the defect repair is made by the technician/project manager. Triggers from SCADA are utilised to modify the planned preventative maintenance schedules. The scheduling of the defect repair is based on the risk of failure.
Planned maintenance	Scheduled annually. Work includes a detailed inspection of components, checking the operation of secondary equipment, insulation resistance, and winding resistance. Components requiring alternate inspection intervals may be completed during inspections at the site.

11.22.4 How we make renewal decisions on the fleet

We apply the DNO Methodology to determine asset health and forecast asset renewal based on the forecast asset health. The specific drivers for asset renewal forecasting and the triggers for selecting specific asset renewal projects (within the overall asset renewal forecast) are shown in Table 146.

Table 146: Drivers and triggers for renewal forecasts and projects

Renewal item	Drivers/triggers
Renewal forecasts	Renewal forecasts are established to ensure that there are no H1 assets present over the forecast period and no unassisted overall failures. Factors that contribute to renewal include: • Aging; • Run hours; • Reliability; • Condition.
Renewal projects	Specific renewal projects are defined and selected based on one or more of the following: • The most current inspection and asset health information (with this information being verified during the project concept phase); • Deteriorating performance (where the underlying reasons for unreliability are attributable to deteriorating asset condition). Because of the value of these assets, they are scheduled for replacement or refurbishment following a project feasibility study (which includes the same factors required for the refurbishment study below).
Refurbishment projects	Refurbishment is considered after the following factors have been considered: • Whether the capacity is still within required load growth forecasts; • The current value of the asset and refurbishment costs vs. the cost of a new generator; • Age; • The extent of the performance or condition issue driving refurbishment,
Defect replacement	Replacement of an asset under fault or defect conditions is typically driven by immediate safety concerns or where the risk of failure is assessed to be possible within the next 24 months.

Renewal item	Drivers/triggers
	It is identified in the strategy for the fleet that assets should not reach a point where performance and risk of failure are compromised. Firstlight is considering the acquisition of strategic spares.

11.22.5 Fleet performance and risks

Current fleet performance

The generator fleet performance is currently acceptable. The transfer of a fleet of aging assets has required the development of a refurbishment strategy to optimise the timing for capital replacements.

Issues with deteriorating moving components associated with wear (run hours) are emerging across the fleet.

Key fleet risks

Our risk register has identified the following top risks (where the consequences are reliability or safety-related):

- Moving component failure (e.g. pistons, pumps and bearings);
- Housing (rust and corrosion);
- Age;
- Ancillary component failures (fuel/coolant lines, radiator).

A key focus of this fleet plan is to ensure that high-risk issues are identified and remediated. In terms of specific risks that are being actively addressed:

Table 147: Specific risks

Active Risk	Actions taken to minimise or mitigate risk
Cylinder head failure	Specialist observation and inspection
Piston failure	Specialist observation and inspection
Alternator (diode, bearing, winding)	Specialist observation and inspection
Mufflers	Renewal and replacement
Housing fire	Scheduled verification of safety systems and compliance. Temperature cutouts and safety systems connected to SCADA

11.22.6 Fleet population and age

Details on populations and age are shown in Table 148. The asset management implications from the age and population are:

- Five 1.0 MVAe generators have reached their MPL. While age is not necessarily an indicator of poor health, recent inspections have indicated that drivers for replacement are present.

Table 148: Asset fleet quantity and age

Type	Type	Population	Average age	MPL[126]	No. of assets within 5 years of MPL
Generator	1.0 MVAe	5	21	20	5
	1.0 MVAe	1	2	20	0
	Truck mount 300 kVAe	1	3	20	0

[126] MPL means maximum practical life. Based on the EEA health determination for Generators

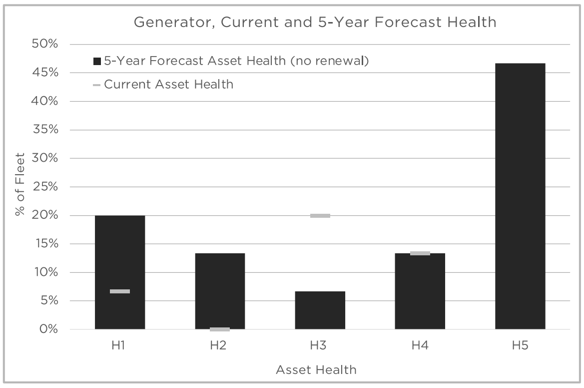
Type	Type	Population	Average age	MPL[126]	No. of assets within 5 years of MPL
	Trailer mount	6	4	20	0
Generator	Site-specific	12	9	20	2

11.22.7 Fleet asset health and forecast maintenance and renewal requirements

Asset replacement and renewal forecasts

For this AMP, the asset health has been calculated using the DNO Methodology, with the results converted to the EEA Asset Indices. The current and forecast asset health for the fleet is shown in Figure 134. The forecast health of the fleet is before renewal.

Figure 134: Asset Health



11.22.8 Expenditure forecasts

The forecast expenditure for the generator fleet is shown in Table 149 and Table 150. Our engineering analysis of the most recent condition data, reliability data, and asset criticality has identified the material projects shown in Table 149. Capex has been forecast based on the level of replacements forecast in Figure 134.

Our forecasts include the installation of two base power units, which operate independent of the network. These are planned for areas where it is now uneconomic to maintain the lines due to the number of faults (caused by planatation forrestry) and where the lines are reaching end-of-life.

We expect the capex forecasts to change in response to the future revisions of our asset health assessments, which will be progressively updated as inspections under the new DNO methodology are completed.

Table 149: Forecast capex

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
1.0 MVAe Mahia Cylinder Head Refurbishment	RSE	114	-	-	-	-
1.0 MVAe Puha Genset Radiator Rebuild	RSE	-	261	260	52	-
1.0 MVAe Te Araroa Cylinder Head Refurbishment	RSE	-	114	-	-	-
Replace Generators 1.0 MVAe	RSE	-	-	1,041	-	1,045
Basepower (Hokoroa Unit)	RSE	143	-	-	-	-
Basepower (Whatatutu Unit)	RSE	227	-	312	-	314

Expenditure type	Capex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Total		**484**	**375**	**1,614**	**52**	**1,359**

Note: Constant 2023 $000.

Table 150: Forecast opex

Expenditure type	Opex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
Generation Fuel	SIE	224	221	221	221	221
Generation Maintenance	SIE	312	351	351	351	351
Total	**SIE**	**535**	**572**	**572**	**572**	**572**

Note: Constant 2023 $000.

11.23 Vegetation

11.23.1 Vegetation Management Strategy

We developed a vegetation management strategy in RY2021. The strategy guided our response to vegetation-related outages.

Having reviewed our recent performance, our strategy remains appropriate, albeit there are some areas where improvements can be made. Our revised vegetation management strategy is shown below.

1. Increase the inspection coverage, including undertaking full feeder inspection using drones when access is limited
2. Actively target vegetation management on the worst-performing feeders
3. Target inspection and remediation work in high-priority areas, including widening the inspection to consider tree-fall hazards on critical sections of feeders
4. Maintain intensive subtransmission vegetation management
5. Increase the engagement with forestry owners to achieve acceptable plantation fall zone clearances and harvesting clearances
6. Improve vegetation maintenance of existing line corridors
7. Implement vegetation management software to improve efficiency and manage data

Actions 2 through 6 are the same as our previous strategy (with updated wording to fit the current context), and actions 1 and 7 are new. We have completed the action concerning fault pick-up, so this has been removed.

11.23.2 Progress and performance

We targeted a 5% improvement in vegetation outages each year (from RY2021 to RY2026). We achieved these targets in RY2021 and RY2022 but missed them in RY2023 due to the significant increase in extreme weather. During the major events of RY2023, we saw significant damage from out-of-zone trees. As a result, we have increased the focus on this issue in our vegetation management strategy (refer to Section 6.4.6).

Our work on managing vegetation has shown positive results. On these feeders, vegetation SAIDI reduced from 18 SAIDI in RY2020 to 8 SAIDI in RY2022. Intensive subtransmission vegetation management has also shown positive results. There was no vegetation-related SAIDI on the subtransmission network in RY2021 and RY2022.

The increase in extreme weather has caused an increase in vegetation outages. Vegetation SAIDI has increased materially since RY2020 due to the increase in extreme weather events. In the RY2023, 90% of vegetation SAIDI occurred during extreme weather (refer to Section 6.4.6).

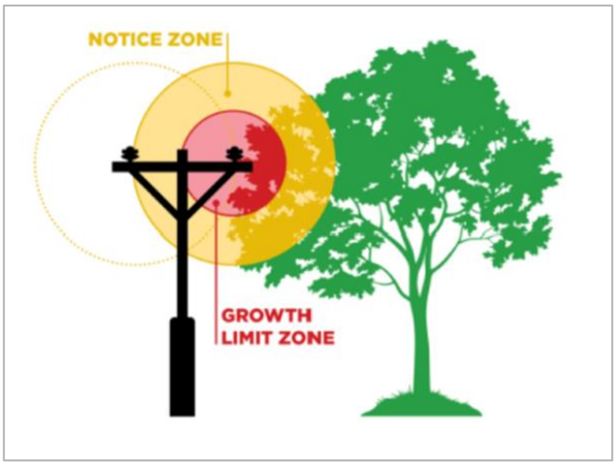
During extreme weather events, vegetation outages are predominantly caused by trees outside the growth limit (refer to Section 6.4.6 for further details). The growth limit is the areas around the lines where Firstlight can trim the trees. A contributing factor to the extent of vegetation-related outages is the network's exposure to forestry plantations, with approximately 7% of subtransmission lines and 10% of distribution lines passing through forestry areas.

11.23.3 Constraints on Firstlight's Vegetation Management

Firstlight's rural network was constructed in the 1950s and 60s and was originally designed to deliver electricity to beef and sheep farms. Over time, there has been a significant change in land use. Farms were sold to forestry, resulting in a conversion to forestry, with a mix of farming usually located at the end of a spur. The change from farming to forestry has seen many of our lines traverse through large tracks of open farmland to running through the middle of large forestry plantations.

Trees within the fall zone are managed under the Electricity (Hazards from Tress) Regulations 2003, which clearly define our responsibilities and those of the tree owners. The regulation aims to protect the safety of the public and the supply of electricity. Under the regulations, trees within the "growth limit zone" must be clear of power lines, as shown in Figure 135 below.

Figure 135: Illustration of the responsibility for trees within the fall zone



Most plantation owners maintain their trees within the Growth Zone limits of 4 meters per the Tree Regulations. However, the trees are now over 30 meters tall and, in high winds, such as those experienced during extreme weather events, come into contact with our line either by falling through the lines or the high winds breaking branches off these trees and throwing them into our lines. This disclosure year, we had several incidents where the trees further back in the plantation fell, knocking the tree next to it over and having a cascading effect until the trees on the fringe fell into our lines.

The adverse weather conditions throughout the period were a key reason for this increase. Wind speeds during Cyclone Hale exceeded 85 km/h, and Cyclone Gabrielle exceeded 150 km/h, toppling many large trees, some of which went through our lines. During the Extreme Weather Days (where wind was a factor), Metservice recorded 56 days with wind gusts above 85 km/h and eight days with windspeeds above 100 km/h.[127] The wet ground conditions throughout the year meant out-of-zone trees fell at lower windspeeds than in prior years.[128]

A Government review is underway on the Tree Regulations, and the ENV and EDBs have made submissions. Submissions for the review included increasing the Growth Limit Zone (GLZ), including risk assessments on GLZ trees, shifting the responsibility to the Person Conducting Business Undertaking (PCBU) for maintaining own trees, providing line-to-sky clearance to prevent overhang, specifying planting clearances, and increased powers to enforce regulations.

11.23.4 Ongoing discussion with plantation owners

Discussions with plantation owners is a critical action for the strategy. These discussions include some positive aspects, including:

- There are multiple small pockets of trees isolated between lines and roads where typically harvesting is expensive. Our negotiations continue with forestry companies to leave these areas unplanted once harvested or relocate the lines outside of the forest;
- It will be challenging to widen current corridors as the universal opinion remains that unless clearing out to a tree length, the process would see the removal of the strongest trees, leaving more vulnerable trees. Clearing to a tree length in a working forest is not viable for the forest due to loss of revenue and carbon credits;

11.23.5 Priority feeder management

We review the vegetation management plan and vegetation performance every six months to monitor implementation, update data on the worst-performing feeders and adjust our target areas as required.

Presently, our priority feeders include Tauwhareparae, Ruakituri, Tikitiki, Hicks Bay, Seaside, Tahora, Borough One, Nuhaka, Raupunga, Matawai, Mata, Inland, Kanakanaia, Whatatutu, Tiniroto. These feeders have been targeted for further investigation, inspection and remediation during FY2023 and RY2025.

11.23.6 Expenditure Forecast

The opex forecast for vegetation management is shown in Table 139. Given the vegetation damage sustained in RY2023 and to support our strategy (particularly on worst-performing feeder management), we have increased our forecast spend on vegetation by $1.1m (18%) over the next five years[129].

Table 151: Forecast Opex

Expenditure type	Opex cat.	RY2024	RY2025	RY2026	RY2027	RY2028
11kV Tree Control Program Northern	VM	715	714	719	719	719
11kV Trees forced cutting	VM	65	65	65	65	65
11kV Tree Control Program Southern	VM	715	714	719	719	719
Subtransmission - Vegetation Control	VM	142	150	150	150	150
Total		**1,636**	**1,643**	**1,653**	**1,653**	**1,653**

Note: Constant 2023 $000.

127 Applicable weather stations were: Te Pohue, Wairoa AerodVMrome, Mahia, Gisborne Aerodrome, Tolaga Bay, Hicks Bay. Source: MetService.
128 The TreeSafe guide states that large branch and tree fall can occur at wind speeds above 80 km/h.
129 Before the change in time-writing process which allocated some of the prior system operations and network support costs to network opex categories. This is explained in Section 14.

12. Risk Management

This section describes the approach to managing risk and summarises the key risks associated with the network assets

12.1 Introduction

Electricity is inherently dangerous and is exposed to a range of hazards. Effective risk management is key to managing the safety and health of people, delivering a reliable service to customers, and protecting the long-term viability of Firstlight.

This section includes details of the risk management policy, framework, key risks, and risk management activities are provided. Also included are details of the emergency response and contingency plans, the approach to managing high-impact/low-probability events, and how Firstlight plans to address climate change risk.

12.2 Risk Management Policy

Firstlight has adopted the Firstgas Group risk management policy, shown below.

RISK MANAGEMENT POLICY

Effective management of risk is central to the growth and success of First Gas. We are committed to developing a culture that provides greater certainty by understanding and managing the risks to our business.

The objectives of risk management within First Gas are to:

- Ensure that the Board and Executive Management are aware of the material business risks;
- Proactively identify and manage risk;
- Ensure that risks are understood so that decisions can be informed to allow opportunities to be realised and risk to be managed;
- Provide assurance to our shareholders that processes are in place to manage risk and to meet our commitments.

First Gas will implement a risk management framework across its organisation to ensure that the objectives above can be met.

This framework will require:

- Alignment with recognised industry standards and good practice
- Inclusion of specific legislative requirements where applicable
- Governance processes with regular updates and reports to the Board and Executive Management Team
- All business units and functions to be responsible for developing and implementing their own risk management plans, based on their strategic objectives and operational needs
- All managers to ensure risk controls are in place and effective for operations within their area of responsibility
- Reporting protocols, including the escalation of significant risks to the Executive Management Team and the Board
- All risks to be assigned suitable owners with the appropriate knowledge and authority to manage them
- Regular, routine reviews of all identified risks, including effectiveness of controls
- Appropriate review of existing and new activities to identify new risks
- Training and awareness for all workers so that risk management is well understood
- The development and maintenance of an environment where all workers are comfortable to raise risks as they arise

To ensure that the risk management framework is implemented and maintained we will make the necessary resources available to make sure that this policy is satisfied.

This policy and the associated risk management framework will be reviewed on an annual basis.

12.3 Risk Management Framework

At Firstlight, risk management activities occur at an operational level, management level, and at a governance level:

- The Board defines the risk appetite and oversees the management of strategic and significant operational risks;
- Management identifies and manages strategic risks and oversees operational risks and associated risk management activities;
- Operational personnel identify and manage risks as part of the normal asset management activities.

Risks are periodically reviewed by management and reported to the Board. This includes a scan for new risks, evaluating whether existing risks have changed, reviewing controls, and considering additional risk treatments[130].

Risks are considered at two levels:

- **Strategic risks** – These are risks that relate to Firstlight's long-term objectives and ability to execute our business plan. They are ongoing risks managed, tracked and monitored periodically but don't generally need a daily focus as embedded systems and processes manage these.
- **Operational risks** – These are risks inherent in the routine operation of the business. These risks are generally near-term or immediate, are actively worked on, and typically have a set timeframe within which the risk will be addressed with appropriate mitigation to reduce the level of risk. From a network perspective, there are two types of operational risks:
    - Generic network risks are enduring risks due to the nature of the business (e.g., use of mobile plant). The controls in place to manage these risks are typically well integrated into business operations;
    - Specific asset risks are risks associated with a particular asset type or site. These risks are identified separately from generic risks, and specific controls and treatments are established.

Defects on the network (e.g. a "red tagged" pole) are a particular type of "specific network risk". Defects are identified through operational processes, undergo immediate evaluation (typically based on safety or reliability), and are then scheduled for remediation.

Risk Manager software manages all strategic and operational risks and follows the Firstgas Group Risk Framework. Defects are managed through the defect management process within Maximo.

12.4 Risk Identification

12.4.1 Risk Analysis

Firstlight uses the Risk Manager software as a database tool that rates risks based on the 5 x 5 risk matrix. As part of the transition to Firstgas Group, the risk matrix has been updated to reflect Firstgas Group's risk management approach. The revised risk matrix will replace the existing matrix embedded in Risk Manager, and a program of workshops is underway to re-align the risk assessments to the new matrix. This work is currently underway and planned to be completed in RY2024.

The 5 x 5 matrix is formed by analysing the consequence and likelihood of a risk affecting the network. The following categories are used as measures:

- People
- Interruption to Supply
- Financial Asset Impact

[130] A treatment is a planned action to further modify the risk.

- Reputation

The 5 x 5 matrix is formed using the following measures:

Figure 136: Firstlight Risk Matrix.

Likelihood	Assets	Catastrophic	Major	Severe	Minor	Trivial
Frequent	Expected to occur once per year or more at a significant location or most sites and common in the industry.	Extreme 25	Extreme 23	High 18	Intermediate 13	Low 8
Occasional	May occur occasionally in the life of the asset (within 1-5yrs) at a significant location or most sites and seen in the industry at least once per year.	Extreme 24	High 20	Intermediate 15	Low 10	Low 7
Unlikely	Unlikely to occur within the life of the asset, but possible within the next 5-20 years and seen in the industry less than once per year.	High 22	High 19	Intermediate 14	Low 9	Negligible 3
Remote	Not anticipated for this asset at this location within the next 20-100 years but heard of in the industry	High 21	Intermediate 16	Low 11	Negligible 5	Negligible 2
Hypothetical	Theoretically possible but would only occur under extraordinary circumstances.	Intermediate 17	Low 12	Negligible 6	Negligible 4	Negligible 1

Risks with a high or extreme residual risk (post controls) are elevated to the Board, where our current controls and treatments are discussed and agreed upon.

All other risks are managed by the relevant risk owner commensurate with the risk type and rating.

12.5 Strategic Network Risks

The following Strategic risks have been identified across the Firstlight.

Table 152: Strategic network risks

Risk title and description	Current controls	Rating[131]
Climate change increases the damage to the network and outages to customers: the effects of climate change, including rising sea levels and more frequent and intense extreme weather events, damaging assets and increasing operational and maintenance costs.	Firstlight has implemented controls to manage climate risk. However, further treatments will likely be introduced over the coming years. Current controls include considering the impacts of climate change in the design of new assets and reducing emissions via a commitment to the Climate Leaders Coalition.	Extreme
Death or injury resulting from activities under Firstlight's control: Firstgas Group employee, contractor or public fatally or permanently injured.	Significant controls are in place, including Health and safety systems, operating procedures, management of safety culture, the public safety management system, employee competency management, driver safety programs, fatigue management, wellness programs, and the contractor management system.	High
Significant power outage to customers: a network failure that results in more than 50% of customers losing supply for more than 8 hours.	Significant controls are in place, including compliance with the asset management plan and good operational practice, emergency response and disaster recovery plans, and participant outage plan.	High
Significant reduction in electricity demand: electricity demand decreases significantly due	In the short to medium term, network revenue is protected through the revenue control regime of the default price path. Maximise the network revenue derived from fixed line charges to the extent permitted.	Low

131 This is the risk rating post-controls. This reflects Firstgas Group's perspective. The assessed risk may be lower for Firstlight.

Risk title and description	Current controls	Rating[131]
to changes in government policies, consumer preferences, or alternative energy sources.		
Failure to support electrification and renewal generation: failure to adopt a customer-centric energy integrator future business model to address threats from technology change - i.e. EVs, SSDG & storage.	Work has commenced to enable the business to support the electrification of transport and heat, the increase in distributed renewable generation, and possible change in the availability of flexibility (demand response).	Low

Health and safety risks are managed "so far as is reasonably practicable" (**SFAIRP**). However, as permanent injury or fatal consequences (in many cases) cannot be eliminated, the residual risks remain high. The high residual risk ensures Firstlight remains focused on ensuring controls are effective and that any treatments are implemented promptly.

Implementing treatments for the strategic risks is an ongoing activity and includes:

- Consideration of climate change risks to the network assets has commenced. Further details on climate change risks are included in 12.5.4 below;
- Emergency response and disaster recovery plans are continually being reviewed to ensure completeness and relevance;
- Preparation of the energy transformation roadmap.

12.5.1 Generic Operational Network Risks

Firstlight has identified and manages 150 generic operational risks. Of these, 42 are rated a high residual risk. The table below provides a high-level summary of the typical risks and controls. In most cases, the residual risk has been accepted.

Table 153: Overview of generic operational network risks

Risk area[132]	Typical risks	Typical controls	Range of Rating[133]
Site and asset hazards	• Unauthorised access • Structure failure • Earth potential rise • Exposure to HV and LV conductors and equipment • Loss of containment of diesel fuel • Rugged and uneven terrain • Loss of supply	• Safe design of structures • Security fencing, signage and access control • Inspection, maintenance, asset health assessment and asset renewal • Employee competency requirements, training, and supervision by a competent worker • Fire suppression • Emergency response • Certification of compliance	Low to High
Hazardous activities	• Operating mobile plant • Worker impairment • Working near roadways • Working at night • Working alone	• Safe operating and maintenance procedures • Plant and equipment inspection, maintenance, and certification	Low to High

[132] Generic risks also cover public safety criteria and controls i.e. fencing, signage, access control
[133] This is the risk rating post-controls. This reflects Firstgas Group's perspective. The assessed risk may be lower for Firstlight.

Risk area[132]	Typical risks	Typical controls	Range of Rating[133]
	• Multiple work parties • Exposure to HV and LV conductors and equipment • Working at heights • Lifting • Live line work	• Employee competency requirements, training, and supervision by a competent worker • Personal protective equipment • Safe work procedures, permit system, and earthing practices • Drug and alcohol management procedures • Fatigue management procedures • Traffic management procedures	
Plant and equipment	• Plant and equipment failure • Injury • Environmental damage	• Safe operating and maintenance procedures • Plant and equipment inspection, maintenance, and certification • Personal protective equipment	Low to High
Physical and environment	• Fire • Exposure to biological hazards • Allergic reactions • Exposure to noise • Confined space work • Oil spills • Rugged and uneven terrain	• Fire suppression • Employee competency requirements, training, and supervision by a competent worker • Personal protective equipment • Emergency response • Safe work procedures	Low to High
Incidents and events causing hazards	• Motor vehicle accidents • Unsecure loads on vehicles • Protection failures • Equipment failure • Loss of supply	• Employee competency requirements, training, and supervision by a competent worker • Network control procedures • Protection design and testing • Emergency response	Low to High
Hazardous substances	• Exposure to hazardous substances • Incorrect storage of hazardous substances • Environmental damage • Exposure to asbestos	• Safe storage and use of hazardous substances • Employee competency requirements, training, and supervision by a competent worker • Hazardous substances register, asbestos register	Low to High

12.5.2 Specific Assets Risks

The asset lifecycle section identified 17 specific asset risks with four risks with a high residual rating summarised in the table below.

Table 154: Specific asset risks

Risk and risk description	Controls	Treatments	Rating[134]
N mechanical security on the 110kV lines: Sections of the 110kV double circuit line from Tuai-Gisborne are constructed on a single tower. A failure of some towers could cause both circuits to trip and, a total loss of supply to the Gisborne region and significant	The existing controls are outlined in the asset fleet plans, including periodic inspection, detailed condition assessments, and corrective and preventative maintenance.	During FY2023, an initial assessment was completed over the entire length of the line that considered all potential failure modes and potential solutions.	High

[134] This is the risk rating post-controls.

Risk and risk description	Controls	Treatments	Rating[134]
SAIDI and SAIFI impact. Safe reconductoring of the line (when due) will require outages on both lines, resulting in significant SAIDI and SAIFI impacts.		The solution for future reconductoring has yet to be resolved.	
Slips near 110kV towers: There are active slips near 12 towers that could result in the failure of the tower. A tower failure could result in a total outage of the Gisborne area and significant SAIDI and SAIFI impacts. Weather events in 2023 have resulted in additional slip areas that need detailed assessment undertaken to understand the potential risk exposure	The existing controls include: • Inspection (as often as weekly); • Geotechnical assessment; • Ground strengthing.	We are undertaking geotechnical assessments on the high-risk sites, remediation plans are being prepared, and remediation is planned for RY2024.	Medium (this risk is included given its relevance to the previous risk)
Lack of spares for ageing of single-phase power transformers: Single-phase transformers are aging on the network. Currently, no stock for the replacement of components is held in stores. Knowledge of how they operate is also becoming scarce. Failure of a unit could result in significant SAIDI and SAIFI impacts.	The existing controls include: • Inspection and maintenance (as outlined in the fleet plans) • Additional budget for sandblasting and painting of the transformers	It is planned that 3 of the 4 units will be replaced over the next five years.	High
IMP transformers corrosion: IMP transformers are corroding faster than expected due to a poor manufacturing process and material. The life expectancy for these units is around 20 years. There is a risk of premature failure resulting in an outage.	The existing controls include: • Transformer bunding • Additional budget for sandblasting and painting of the transformers • 4 monthly inspections	There are no further treatments planned. However, additional maintenance will be undertaken based on asset condition	High

12.5.3 Managing High Impact Low Probability Events

High impact low probability (**HILP**) events are events that have a larger impact than what is allowed for in the normal system planning criteria. This includes extended contingency events (i.e. loss of two or more system components), common mode failure events, and domino effect failures (i.e. failures causing subsequent systems to fail). It is hard to predict how these events may eventuate because they have multiple failure modes. One example of these events was experienced in December 2016 when a light plane crashed into the Tuai-Gisborne 110kV double circuit line, interrupting supply to 20,613 customers for 33 hours.

Since the failure modes of these events are unpredictable, the focus is on impact-reducing mitigations. The asset management processes address a HILP risk through:

- Progressing asset management strategy initiative #1 to improve network resilience. The scope of this initiative has been expanded, and additional work is planned (refer to Section 10);
- Setting security of supply standards and incorporating a level of resilience appropriate for the number of customers, and implementing development plans to ensure the network meets the required level of security;
- Maintaining assets to updated codes, e.g. NBS standards and AS/NZS7000, which results in assets being progressively upgraded to ensure resilience to earthquakes and an improved response to storm events;

- Improving operational response by having appropriate contingency plans in place for extended contingency scenarios;
- Taking an active role in Civil Defence and Emergency Management activities in preparedness for a major natural disaster event;
- Establishing contingency plans to deal with the consequences of known risks and significant outages on the network;
- Utilising standardised equipment on the network so that equipment can be reallocated/rebuilt quickly in the event of failure. Standardised designs and components are easier to repair and reconfigure if necessary;
- Undertaking a detailed risk assessment on the Tuai-Gisborne 110kV line;
- Developing a solution to increase the diversity of supply on the Tuai-Gisborne 110kV line.

12.5.4 Assessing and Managing the Impact of Climate Change

Firstlight is exposed to a range of climate-related risks. During FY2022 and FY2023, some initial work was undertaken to improve the understanding of these risks and the potential impact on the business. The effects of the extreme weather events during FY2023 have slowed down our progress in this area.

The initial view is that there are likely to be two "themes" to climate change risks:

- Firstly, it is likely that climate-related changes will increase the energy transformation (which is discussed in Section 10). Planning and preparing for this transformation will be necessary to support New Zealand's climate change response;
- Secondly, climate change will affect weather patterns, which could impact the network. The result has seen an increase in extreme weather events such as wind, floods and snowstorms, or longer-term shifts such as a gradual temperature increase and sea level rise.

A qualitative analysis of climate risk is based on a 15-year outlook with risks rated on a scale of low to high. Given the industry's unique regulatory environment, the risks are assessed against the ability to meet reliability and quality targets.

Preliminary analysis indicates the most significant network risk from climate change is likely to be from:

Table 155: Climate change network risks

Risk and risk description	Controls and treatments	Rating[135]
Vegetation contact and tree fall: Vegetation contact and treefall are some of the biggest challenges in maintaining network reliability. Vegetation issues are expected to increase due to weather events and higher growth rates from warmer temperatures.	A vegetation management plan has been developed, which will need to adapt to changes in growing conditions. As part of this plan, work with forestry plantation owners, Councils, and the community will increase to explain the importance of controlling vegetation near power lines. Forecast expenditure has increased over the planning period to enable more vegetation management to be completed. The vegetation management plan was reviewed and enhanced following the extreme weather events of RY2023.	High

[135] This is the risk rating post-controls. Risk assessment is not yet completed hence no rating has been applied for these individual risk areas.

Risk and risk description	Controls and treatments	Rating[135]
Extreme weather and storms: Overhead lines are more at risk from severe storms and high winds, which means rural customers and coastal communities are exposed to this risk. Damage to the network due to severe storms, floods, landslips, and winds can also create a safety risk. Extreme weather events also damage the roading network, making access to the network difficult and extending repair times.	We have revised our resilience strategy (asset management strategy #1) in response to the increase in extreme weather events being experienced. This initiative is focused on assessing new hazards (flooding, landslips and wind) and preparing mitigation plans, remediating the worst-performing feeders, accelerating the wood pole replacement program, enhancing our contingency and response plans, enhancing vegetation management, and increasing distribution network automation and security. All these areas will assist in mitigating the impact of extreme weather and storms.	High
Sea level rise: Sea level rise over the next 25 years may affect some parts of our network.	Further analysis will be undertaken of the potential impacts during RY2024 and RY2025.	Low

Whilst we have not completed our work in this area (which will take some years to complete), we are comfortable that the strategy established is appropriate for managing the impacts of climate change. Our asset management strategy contains four key initiatives that contribute to the management of climate change risk:

- Initiative #1: Improve network resilience;
- Initiative #2: Enhance vegetation management activities;
- Initiative #4: Increase the level of security and automation on the network;
- Initiative #5: Ensure the network can support the energy transformation and decarbonisation of the region.

12.5.5 Resilience Management Maturity Assessment

The Electricity Engineers Association (EEA) developed a guideline recognising the importance of good resilience planning that supports effective management of issues arising from major emergency episodes and other extreme events that may result in critical supply interruptions.

The guide was developed to cover the principles of emergency management preparedness and provide a practicable self-assessment to enable the organisation to rate its overall resilience. The assessment is constructed around the 4R framework defined in the National CDEM Plan.

Firstlight undertook the self-assessment to baseline the organisation's resilience maturity. The overall score was 2.8 (out of 4, where 3 is "competent"). We scored three or above in readiness, response and recovery activities and 2.8 lower in risk reduction. Improving risk reduction is a key focus of our resilience strategy. The full assessment results are included in our resilience strategy (refer to Section 10).

12.6 Emergency Response and Contingency Plans

12.6.1 Emergency Response

The nature of the business is such that every unplanned supply outage invokes an emergency response of some degree.

A small-scale emergency response typically involves part or no power to one or more premises and third-party damage to network assets. These types of events occur daily. In any one day, 5 to 20 events are typical. Well-developed processes are in place to manage these events.

Large-scale events that require an emergency response to a greater degree include extreme weather (e.g. wind, snow, lightning storms), earthquake, tsunami, and major flooding. Large events typically relate to extreme weather and occur 4 or 5 times per year.

In these large-scale events, the normal emergency response process becomes swamped; hence, additional resources and prioritisation are required for effective management. To manage this, a workplace emergency response plan operates that involves:

- Assessment and notification that a major event has occurred: This may include coordination with emergency services, civil defence, or the system operator;
- Escalation of resources: an emergency management team is established, and additional resources are called in as required. For very large events, this may involve mobilising additional external contractors;
- Response: the event is analysed, and work is prioritised, dispatched and actioned as required (in coordination with other agencies as required);
- Support: A support services team is established to ensure the needs of personnel are being met for long-duration events;
- Coordination and communication: Personnel are assigned to coordinate Firstlight's restoration activities with other agencies (typically Civil Defence) and to communicate the network status to stakeholders (e.g. directly to key customers, social media, media, local government, Iwi, etc.).

Prioritisation for restoration is event-specific but is generally focused on (in order or priority):

- Critical infrastructure, such as water supplies, sewage systems, hospital / medical facilities, and communications facilities;
- City areas where large customer numbers are disrupted;
- Commercial businesses involved in servicing emergency needs, e.g. fuel, food;
- Rural townships;
- Main line rural areas;
- Spur line rural areas.

12.6.2 Contingency Planning

Contingency preparedness is documented within ENL16 Section 5 - network emergency response document.

Of relevance to the network:

- The network control room is in Carnarvon Street, Gisborne. If, for any reason, the control room is unavailable, the operational control falls to the backup facility at the Gisborne Substation (where a backup control room has been established). In addition, operational facilities can be established at most network zone substations. Manual operation is also available for all assets if failure of the SCADA system or auxiliary supply system occurs;
- In the event of major disruption concerning office access or communications, remote centres have been designated across the region to enable decentralised planning and continued operations at a localised level. Independent control will be delegated to a person based at each remote centre;
- Multiple communication methods are in place via the RT network, IP/fibre network, and mobile phone network;

- Paper management systems are available to cover any failure of computer systems.

A participant outage plan has also been prepared following The Electricity Commission's requirements. This plan covers the methodology and processes for managing two types of events.

- Category A events - these events evolve and occur when a shortfall of energy available for supply is expected. In these events, Firstlight is required to provide a reduction in energy usage based on a comparison with typical/normal energy usage. This is achieved by the operation of the standby diesel generation, shedding of hot-water load via load control for extended periods outside of normal service levels, and rolling outages in line with predetermined priorities;
- Immediate (Category B) events – These events occur with little or no warning, usually due to a transmission line or major generation failure. These types of events will generally result in a declaration of a grid emergency. In these events, there is a requirement to provide a reduction in demand at GXPs. Depending on the available time frame, this is achieved by operating the standby diesel generation, shedding load via load control, and interrupting load in line with predetermined priorities.

12.6.3 Vulnerable Customers

A process is in place to accommodate supply interruptions affecting customers with special medical needs.

Where notification of customers with special needs is identified, the customers are advised to prepare an individual emergency plan to ensure their needs can be met should there be an interruption to their supply. Action plans covering short-term and long-term outages are necessary, and battery backup systems or emergency transport plans are arranged between the customer and their healthcare provider.

13. Project Delivery and Deliverability

This section describes the approach to delivery and assessment of capabilities to deliver on this plan

13.1 Introduction

This section identifies and discusses the *design and construct* phase of Firstlight Network's asset lifecycle.[136]

13.2 Design and Construction Standards and Processes

The design and construction standards were developed to increase the efficiency and quality of the work and equipment on the network. These design and construction standards have evolved over the years due to changes in materials and engineering staff.

Regarding equipment specifications, most equipment is standardised, except for large equipment purchases. In this case, equipment and manufacturers are chosen based on tender submissions and ranked based on criteria relevant to the project and requirements stated in the specifications.

Quality systems manuals are updated when any changes are made to the equipment, procedures or processes on the network.

13.3 Inspection and Maintenance Standards

During RY2021 and RY2022, inspection standards were revised for key assets to align with the DNO Methodology.

Maintenance standards for primary equipment (i.e. power transformers, circuit breakers, etc.) are typically in line with the manufacturer's specifications and recommendations, as these are very specific in terms of maintenance detail. For assets such as poles, structures and conductors where recommendations vary depending on the manufacturer, Maintenance documents to standardise the process.

Inspection frequency is typically varied based on the criticality of the asset (refer to Section 11). However, there are other drivers, such as best practice guidelines and regulations, which also set the frequency of inspections. Capability of contractors and cost can sometimes limit the extent to which this work can be completed, but the aim is to achieve targets within best practice guidelines.

In terms of the inspection type (e.g. visual/testing), this also depends on criticality. Inspection programmes for the 110kV towers are more extensive than for the 11kV rural lines, as the consequences of failure differ substantially.

Quality systems manuals were established in 2012 (specifically the maintenance manuals), with minor changes over the years based on best practice changes or regulatory requirements.

13.4 Operating Procedures

Firstlight Network's operational procedures are located within the quality system manuals. Operational procedure manuals cover areas such as:

- Asset management;

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[136] A description of the phases of the asset lifecycle are provided in Section 2.6

- Works management;
- Purchasing;
- Customer complaints;
- Easements and leases;
- Risk management;
- Project management.

The network control rooms' operational procedures are separated from the main procedures, as the importance and significance of these procedures warrant their own section. For example, these procedures cover:

- Work applications;
- Switching;
- Permits and assurances;
- Reclose blocks;
- Close approach;
- High loads;
- Fault response;
- System controller responsibilities.

The introduction of Maximo in RY2023 has changed the procedures for several of these areas. We will be aiming to update these in FY2024.

13.5 Deliverability Assessment and Improvement

13.5.1 Deliverability Assessment

A review of our delivery of the works plan is presented in Section 6.6 Over the past two years, Firstlight delivered over 95% of the planned capital works program for all but one category.

We have also been delivering well against our planned vegetation management and planned maintenance and inspection programs over the past two years. Vegetation management has been 6% and 7% behind plan for the last two years. The performance was impacted by the high number of storm events over those two years, which diverted resources onto emergency response work.

Planned maintenance and inspection work was 20% ahead of plan in RY2022 and 21% behind in RY2023. We accelerated inspection work in RY2022, which drove higher costs. We were behind plan in RY2023 due to the high number of storm events over those two years, which diverted resources onto emergency response work.

13.5.2 Planned Improvement in Delivery

The acquisition by Firstgas Group Limited will see Firstlight Network's processes in deliverability transition over time to adopt and align with well-developed Firstgas delivery strategies and framework. Evaluating and integrating best practices from both groups ensures first-class services and continuity are maintained for all customers.

Investment training programmes will continue to increase the number of trained local contractors. This is seen as critical to maintaining and servicing assets efficiently. Additional contractors will likely be required in this field to maintain the level of expenditure forecast (specifically in fault response).

External companies have historically carried out the acquisition of land easements. The delays and ineffectiveness of this approach have required projects to be deferred. With the transition to Firstgas Group, the intention is to manage easements and acquisition of easements internally and engage with contractors when needed to support the delivery.

13.5.3 Delivery Outlook

The network capex forecast for the next five years averages $15.6 million. The increase in investment reflects the ongoing needs of the network. The focus of the Capex work over the next five years is asset replacement and renewal investments.

Wood pole replacements and the GIS-TUI thermal upgrade work are the most material projects over the next five years. The resourcing for this work is sourced externally, and Firstlight is comfortable that we will be able to secure the necessary skills from outside the region.

We are commencing installing new generators and refurbishing our generator fleet. This will require new skills, and we will be looking to build these over the next year.

The costs associated with the zone substation work have a significant material component, with the resource requirements being less significant.

14. Financial Forecasts

This section summarises the expenditure forecasts included in the asset management roadmap and lifecycle plans

14.1 Introduction

This section outlines the material changes in our expenditure forecasts over the 2022 AMP. Detailed expenditure forecasts have not been repeated from prior sections, nor have the forecasts contained in Schedule 11a and 11b been replicated that are attached to this AMP.

Our commentary in this section references constant dollars.

14.2 Material drivers for the change in expenditure forecasts

14.2.1 Summary of changes

Our forecast capital and operational expenditure have increased.

The network capex forecast for the next five years averages $15.6m (refer to 137). This is an annual increase of $3.6m over the 2022 AMP. The material drivers of the increase were:

- An increase in renewal of our overhead assets;
- Dealing with geohazards on the 110kV line that supply Gisborne and Wairoa;
- Refurbishment of our aging generator fleet and increasing their use to improve resilience;
- Upgrading our SCADA system and implementing an OMS;
- The impact of inflation on the cost of doing work.

Total Opex averages $15.2m over the next five years (refer to 138). This is a $2.8m p.a. (18%) increase over the 2022 AMP. The material drivers of the increase were:

- Higher emergency response costs;
- Increasing the amount of vegetation management work;
- Accelerating the completion of our inspection program;
- A reduction in the capitalisation of SONS costs (with a corresponding decrease in capex);
- The impact of inflation on the cost of doing work.

Figure 137: Capex forecast

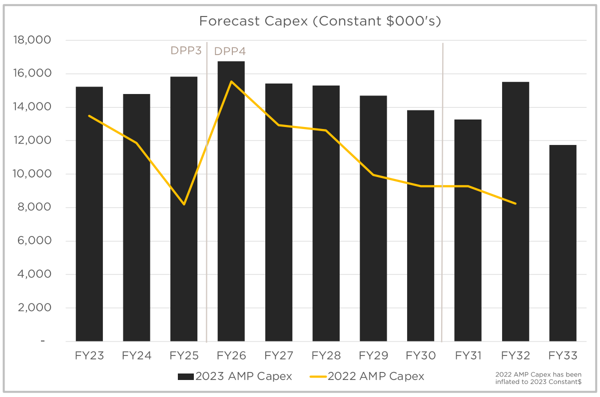
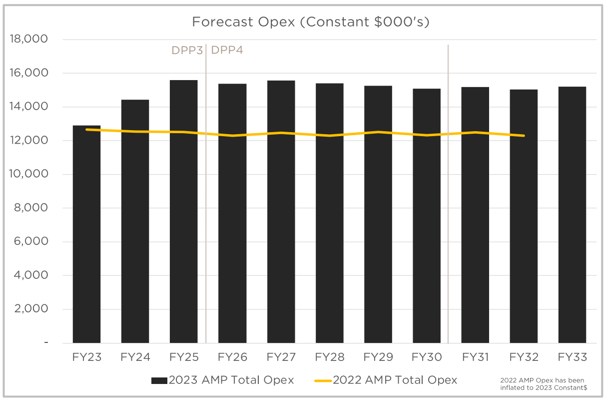


Figure 138: Opex forecast



14.2.2 Changes in time-writing and capitalisation process

The transition to Firstgas Group systems introduced new time-writing processes at Firstlight. This transition has resulted in some changes to opex and capex:

- The level of capitalisation of business support (**BS**) and system operations and network support (**SONS**) costs has been reduced. This has increased BS and SONS costs;
- The time-writing of some SONS costs to network opex categories. This has offset the increases mentioned above. Within the SONS team, some staff undertake asset inspections, vegetation administration and other work that directly relates to network opex, and these costs have now been forecast as network opex.[137]

Our commentary on the changes to network opex forecasts explains this on a comparable basis.

14.2.3 The impact of inflation

The escalation of costs over the past two years has been significant over the past two years. In our 2022 AMP, we have incorporated cost increases where we made changes to projects and programs but did not incorporate wholesale escalation in the cost of doing work as we had not determined whether the cost increases were permanent.[138]

For this AMP, we reviewed all significant projects and adjusted project costs based on our material and labour cost escalation assessment. We saw a material rise in the cost of doing work for some projects and programs, with some project costs increasing by 20%. For other projects and general expenditure provisions, we applied inflation at 6.2% between September 2021 (2022 Constant Prices) and September 2022 (2023 Constant Prices).

14.2.4 Forecast expenditure vs. our regulatory allowances

The increase in capex is significantly more than our current regulatory allowance. We are forecasting overspending our capex allowance by 59% in RY2024 and 67% in RY2025.

The increase in opex is also significantly more than our current regulatory allowance. We are forecasting overspending our capex allowance by 28% in RY2024 and 38% in RY2025.

The overspending of the capex and opex forecasts will result in a cost to Firstlight under the incremental rolling incentive scheme (equal to 23.5% of the overspend). The cost to Firstlight is offset to some degree by the inflation adjustment applied to future prices.

14.3 Capital Expenditure Forecasts

Total capital expenditure for the planning period (RY2024 – RY2033) is $150.8m. Graphs showing the forecast expenditure vs. the 2022 AMP forecasts for each expenditure category are shown in Figure 139 to Figure 145. We discuss each expenditure category in the section below:

Figure 139: Capex Forecast

Category	RY2024	RY2025	RY2026	RY2027	RY2028	RY2024 -2028	RY2029-2033
Customer Connections	140	117	118	119	121	615	633
System Growth	782	1,177	1,761	3,311	3,738	14,469	15,798
Asset Replacement and Renewal	13,085	12,261	11,831	9,416	9,869	54,615	48,752
Asset Relocation	51	51	51	51	51	256	257
Reliability, safety and Environment							
Quality of supply	203	1,731	1,270	2,215	88	5,507	2,213
Legislative and regulatory	183	190	35	36	37	481	92
Other	191	136	181	970	129	1,607	2,519

[137] Our approach was to apply a contractor lense to these resources. That is, if the staff would ordinarily be part of a field services contractor performing the work then their costs were time-written to network opex. Our assessment was taken over a relatively short period, and our allocations (for forecasting purposes) may change over the coming years.

[138] 2022 AMP, Section 9.5.

Category	RY2024	RY2025	RY2026	RY2027	RY2028	RY2024 -2028	RY2029-2033
Non-Network	311	255	589	254	255	1,664	1,280
Total	**14,946**	**15,840**	**16,799**	**16,295**	**15,333**	**79,213**	**71,544**

14.3.1 Customer Connections

Other than the increase in capex in RY2024 concerning an allowance for some additional switchgear for a known new connection, there is no material change in customer connection capex. The slight increase in customer connection capex beyond RY2027 is due to growth in connections

14.3.2 System Growth

The material system growth projects over the next five years are:

- The Massey Road zone substation;
- Mahia zone substation and the upgrade of the 400V network in Mahia;
- The installation of capacitors at Gisborne substation;
- The reconfigure and upgrade of the transformers at the Wairoa substation.

The changes to the system growth forecasts for RY2024 to RY2029 were due to:

- The deferment of $2.3m of thermal upgrade work to the second five-year period. The delay was due to the capacitor upgrade in RY2026 providing sufficient capacity until the back end of the planning period;
- $780k for the new Wairoa reconfiguration and transformer replacement program;
- The $460k increase in the allowance for transformers and network extensions. The forecasts reflect current costs, which have increased over the past few years;
- $820k for the increase in the scope of the Mahia 400V upgrade project.

14.3.3 Asset Replacement and Renewal

Asset replacement and renewals are $54m for RY2024 to RY2029, which is 70% of our capital program. The material renewal programs are:

- The ongoing wood pole replacement programme is $32m over the next five years. This is an increase of $9.8m over the 2022 AMP as we accelerate the replacement program to address additional low-health poles identified in recent inspections and in response to cyclone Gabrielle damage;
- The management of geotechnical risks on the 110kV tower lines. This is a $2.6m program over the next five years, an increase of $2.1m;
- The refurbishment of our diesel generator fleet. This is a new $2.9m program;
- The renewal of zone substation equipment (which is primarily indoor and outdoor switchgear). This $2.8m program has increased by $1.9m.

14.3.4 Asset Relocations

There has been no material change to our allowance for asset relocations.

14.3.5 Reliability, Safety, and Environment

Over the next five years, reliability, safety, and environment expenditure is $7.6m. This is an increase of $4.6m due to an increase in the quality of supply projects. The material reliability, safety, and environment projects and programs are:

- The installation of three additional generator sets at Raupunga, Frasertown and Ruakituri (two of which fall into the RY2024 to RY2028). This is new expenditure of $2.1m over the next five years;
- Upgrades and enhancements to the SCADA system, including developing an OMS. This is new expenditure of $2.2m;
- New 100kVA and 350kV portable generators. This is new expenditure of $155k in RY2024;
- Expanding the automation program and upgrading protection on the 50kV coast feeder. This is an increase of $316k;
- The continuation of the galvanised box replacement program at $500k;
- 11 kV zone substation switchboard replacements (due to compliance issues). This is a $900k program, most of which is new expenditure.

14.3.6 Non-network Assets

Expenditure on non-network assets has increased by $500k to $1.6m over RY2024 to RY2028. The material changes included a new Wairoa office and increasing the allowance for vehicle replacements in RY2024 and RY2025.

14.3.7 Customer contributions and vested assets

Customer contribution and vested assets are discussed in Section 10.

14.3.8 Capex Expenditure Graphs

Figure 140: Capex – customer connections

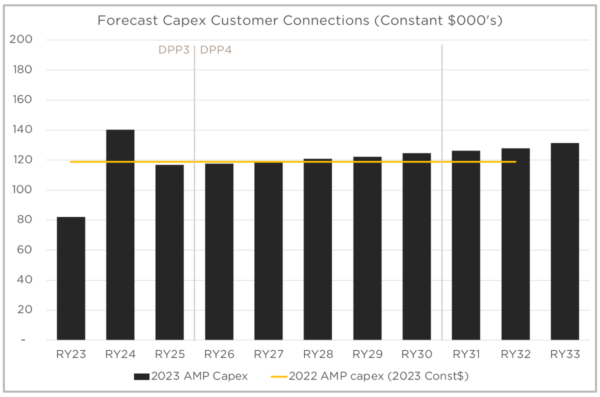


Figure 141: Capex – system growth

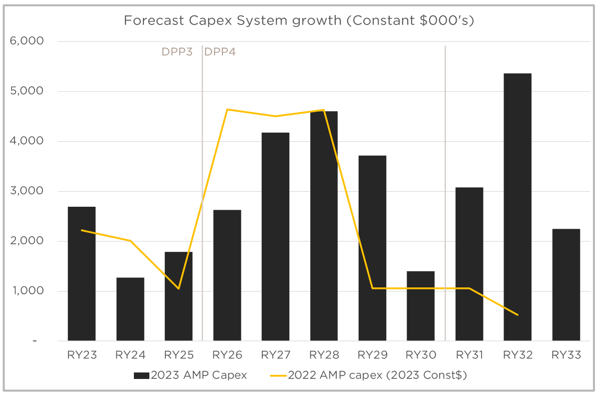


Figure 142: Capex – asset replacement and renewal

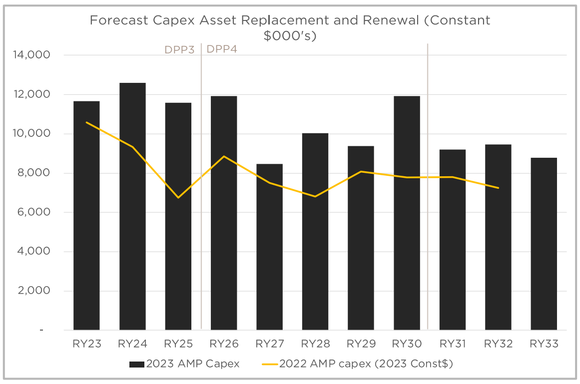


Figure 143: Asset relocation

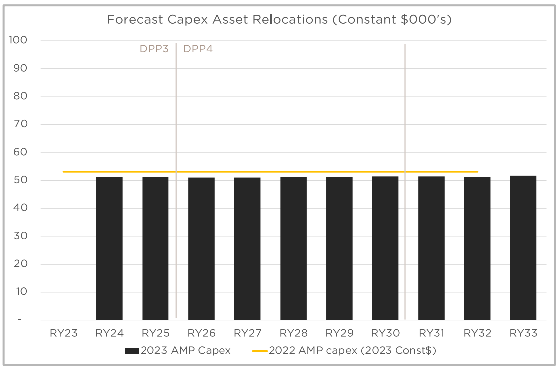


Figure 144: Capex – Capex – reliability, safety and environment

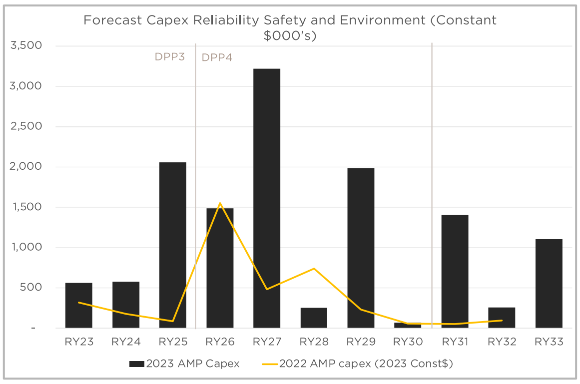
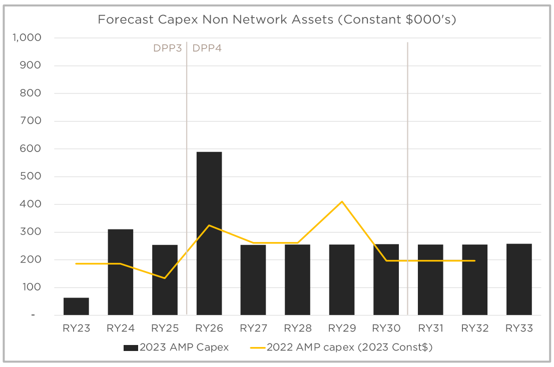


Figure 145: Capex – non-network assets



14.4 Operational Expenditure

Total network opex and non-network opex for the planning period (RY2024 – RY2033) is $82m and $70m respectively. Graphs showing the forecast expenditure vs. the 2022 AMP forecasts for each expenditure category are shown in Figure 147 and Figure 152. We discuss each expenditure category in the section below:

Figure 146: Opex Forecast

Category	RY2024	RY2025	RY2026	RY2027	RY2028	RY2024-2028	RY2029-2033
Service interruptions and emergencies	2,615	3,078	3,078	3,078	3,078	14,927	15,391
Vegetation management	1,636	1,643	1,653	1,653	1,653	8,240	8,267
Routine and corrective maintenance and inspection	3,058	2,909	2,759	2,942	2,759	14,427	14,311
Asset replacement and renewal	859	855	793	800	808	4,116	2,337
System operations and network support	2,264	2,993	2,993	2,993	2,993	14,234	14,963
Business support	4,000	4,102	4,102	4,102	4,102	20,410	20,512
Total	**14,432**	**15,581**	**15,378**	**15,569**	**15,394**	**76,354**	**75,780**

14.4.1 Service Interruptions and Emergencies

Service interruption and emergency opex have increased by $1.0m p.a. (on a comparable basis before the time-writing) over the 2023 AMP ($1.18m including time-writing). These costs are consistent with expenditure over recent years and reflect the likelihood of ongoing extreme weather events. It also now includes operating costs (i.e. diesel) associated with operating the gensets, which was previously excluded.

The cost increase is before accounting for the implementation of our resilience strategy. The resilience strategy's goal is to reduce the impact of extreme weather. Hence, when implemented, service interruption and emergency opex will be reduced[139]. When we have included the full capital costs of the resilience program in our forecasts, we will include the benefit (i.e. reduction) in emergency response opex.

Expenditure on unplanned equipment failure and faults remains steady with forecasts based on historical expenditure levels.

14.4.2 Vegetation Management

As mentioned in Section 11, we have increased our forecast for vegetation management work by $210k p.a. (on a comparable basis before the time-writing allocation). The inclusion of the time-writing allocation presented the full cost of our vegetation management work.

The increase in expenditure includes costs associated with vegetation issues identified post-cyclone Gabrielle.

14.4.3 Routine Corrective Maintenance and Inspections

Routine and corrective maintenance and inspection costs increased by $400k p.a. (on a comparable basis before time-writing). The inclusion of the time-writing allocation presented the full cost of our Routine and corrective maintenance and inspection work.

We are increasing network inspection activity as our asset fleets age. We are accelerating our inspection program, so we complete all planned inspections as shown in Section 6.

[139] The cost of new generators has been included, however this doesn't reduce the impact (damage) to the network; rather these are a means of maintaining supply.

We have also included maintenance costs associated with the diesel generator fleet.

Due to the impact of the cyclones in early 2023, work was deferred to allow the Firstlight team to focus on recovery. The forecast includes the completion of this deferred work.

14.4.4 Asset Replacement and Renewal

This expenditure includes work such as transformer refurbishments, tap-changer maintenance, and painting, with several substation sites located within 2km of the sea, this expenditure is seen as vital to maintaining the assets in good operating order. The changes in this category are primarily due to the impact of inflation and time-writing.

ACOD expenditure associated with the generators that provide flexibility (e.g. Waihi Hydro for Wairoa substation transformer deferment) are included in this category.

14.4.5 System Operations and Network Support

System operations and network support (**SONS**) costs are broadly the same as forecast in the 2022 AMP. However, below the headline, there has been some movement:

- We have reduced the level of capitalisation of SONS costs on capex projects (lower capex costs) but increasing SONS;
- There has been an increase in IT costs, primarily due to the inclusion of software as a service expenditure (SaaS);
- These increases have been mainly offset by time-writing some previous SONS costs to their appropriate network opex categories. This now provides an accurate picture of the network opex costs.

14.4.6 Business Support

Business support costs are consistent with prior forecasts. The slight increase reflects inflation's impact and movement in some cost inputs. The changes are not material.

14.4.7 Opex Expenditure Graphs

Figure 147: Opex forecast – Service interruptions and emergencies

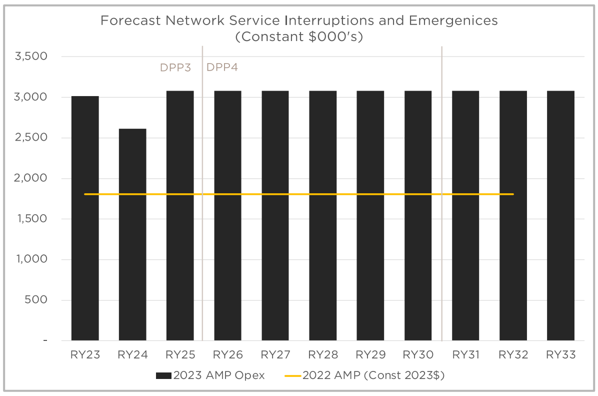


Figure 148: Opex forecast – vegetation management

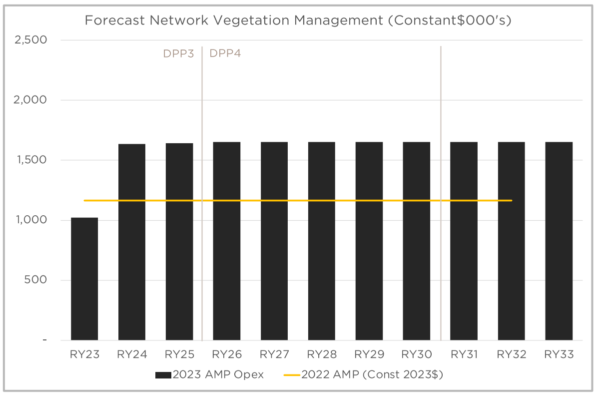


Figure 149: Opex forecast – Routine and corrective maintenance and inspection

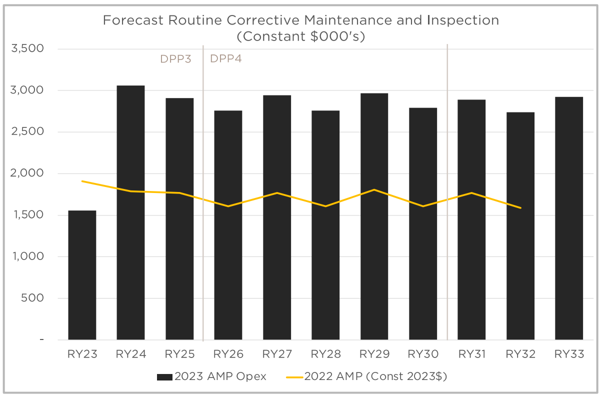


Figure 150: Opex forecast – asset replacement and renewal

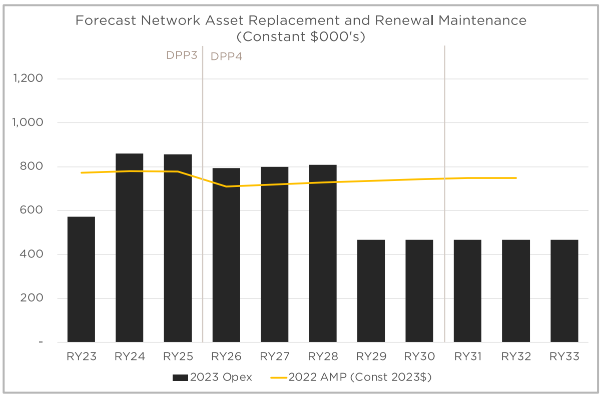


Figure 151: Opex forecast – System operations and network support

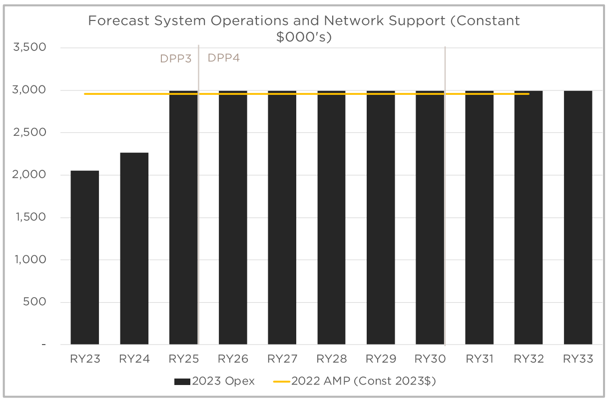
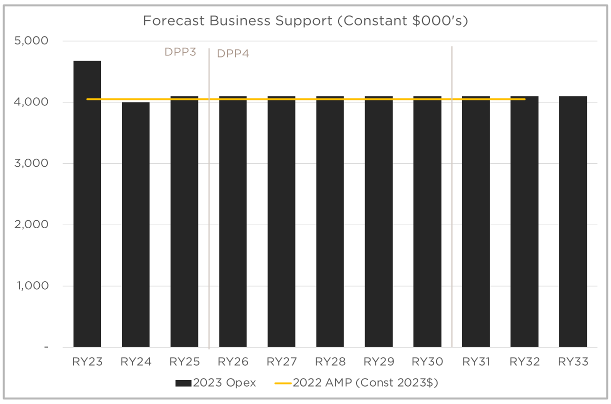


Figure 152: Opex forecast – Business support



Appendix 1

Key Terms and Acronyms

AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air-Break Switch
AC	Alternating Current
ACSR	Aluminium Conductor Steel Reinforced
ACOD	Avoided Cost of Distribution
ADMD	After Diversity Maximum Demand. A software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid.
ADMS	Advanced Distribution Management System. A measure of the demand for an average customer. It is calculated as the maximum demand of the system divided by the total number of customers.
Adverse environment cause outages	All unplanned interruptions where the primary cause is adverse environment, such as slips or seismic events.
Adverse weather cause outages	All unplanned interruptions where the primary cause is adverse weather, other than those caused by directly by lightning, vegetation contact or adverse environment
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
ARR	Asset Replacement & Renewal
AUFLS	Automatic Underfrequency Load Shedding
CAPEX	Capital Expenditure
CB	Circuit Breaker
CPI	Consumer Price Index
CPU	Central Processing Unit
CT	Current Transformer
Controllable DER	DERs whose output or consumption can be increased or decreased on demand – for example, diesel generation, batteries, and controllable EV chargers, but not intermittent renewable generation like wind or solar. The impact of controllable DERs is flexibility.
Defective equipment cause outages	All unplanned customer interruptions resulting from equipment failure, either mechanical or electrical
DER	Distributed Energy Resource. Distribution connected assets that either reduce load or inject more power – whether generation (like solar panels), storage (like batteries), or automated load management devices.
DGA	Dissolved Gas Analysis
DNO	Distribution Network Operators
DNP	Distributed Network Protocol
DPP	Default Price Path (Commerce Commission)
DSO	Distribution System Operator. Entities responsible for managing energy and other services (like flexibility services) across the distribution network.
EDB	Electricity Distribution Business
EOL	End of Life
ENL	Eastland Network Limited
EV	Electric Vehicle

FY	Financial Year
GIS	Geo-Spatial Information System
GPD	Group Peak Demand
GM	Ground mount
GXP	Grid Exit Point
Feeder	The lines and cables that distribute electricity from zone substations to distribution transformers.
Flexibility Purchaser	These are buyers of flexibility services and could be: • Energy retailers or generators who buy alternatives to energy on the spot market; • System operator who buys reserve energy alternatives or ancillary services alternatives; • Transpower, who buys alternatives to transmission assets; • Distributors, who buys alternatives to distribution assets.
Flexibility Markets	Mechanisms for matching and rewarding traders of controllable DERs, including providing dispatch instruction in response to prices.
Flexibility resources	Flexibility resources are delivered through DERs that are controllable. Distributed solar without a battery is not a flexibility resource because it is not controllable.
Flexibility Traders	Owners of DER portfolios who manage their DERs portfolio to allocate it to its highest value usage. Flexibility traders interact with flexibility buyers to provide the flexibility that they require. Importantly, flexibility traders maximise the value of DERs by allocating them to their highest value use ("value stacking") rather than dedicating individual DERs to one use.
GXP	Grid exit point. The point of connection between the distribution network and the transmission network
H1	A measure of asset heath. End of serviceable life. Immediate intervention required.[140]
H2	A measure of asset heath. Material deterioriation but condition still within serviceable life parameters. Intervention likely within three years.[140]
H3	A measure of asset heath. Normal deterioriation requiring regular monitoring[140], but with an increasing risk of failure.
H4	A measure of asset heath. Normal deterioriation requiring regular monitoring.[140]
H5	A measure of asset heath. As new condition.[140]
H&S	Health & Safety
Hosting Capacity	The amount of new production or consumption that can be connected to the network without endangering the reliability or voltage quality for other customers.
HR	Human Resources
Human error cause outages	All unplanned customer interruptions resulting from contractors or staff, commissioning errors, incorrect protection settings, SCADA problems, switching errors, dig-in and overhead contact
HV	High Voltage. Voltages typically above 1,000 Volts.
ICP	Installation connection point. The point of connection for an electricity consumer.
IP	Internet Protocol
IT	Information Technology
KVA	Kilo-Volt Amps
Lightning cause outages	All unplanned customer interruptions where the primary cause is a lightning strike, resulting in insulation breakdown and or flashovers. Typically protection is the only observable operation
LMT	RPS switchgear type
LV	Low voltage. The final distribution voltage for the lines and cables that connect consumers to the network.
m	Million

140 EEA Asset Health Indicator defintion.

MD	Maximum Demand. The peak demand (measured in MW or MVA) for the network, element of the network, or load.
MDI	Maximum Demand Indicator
MED	Major Event Day
MPL	Maximum Practical Life. the age at which the majority of assets can be expected to have been removed from service. Approximately defined as the age where nominally 95% of assets from the population would be retired for end-of-life reasons.
MV	Medium Voltage
MVA	Megavolt-Amps. A unit of electrical capacity or electrical load. Includes both real and reactive power. Also called apparent power.
MVAr	Megavolt-Amps (reactive)
MWh	Megawatt Hour. A unot of energy.
NZ	New Zealand
N-1	A measure of network security. The capacity available after the loss of the largest network element.
N-1-g	A measure of network security. The capacity available after the loss of the largest network element and the largest generation unit.
OPEX	Operational Expenditure
OOU	Onset of Unreliability. the nominal age at which replacement drivers first become evident within the population. Approximately defined as the age where 5% of assets would be retired for end-of-life reasons (excluding capacity-related reasons)
PILC	Paper Insulated, Lead Covered
PLC	Programmable Logic Controller
PoF	Probability of Failure
POS	Point of Supply
PV	Photovoltaic (Solar)
PVC	Polyvinyl Chloride (Cable)
PM	Pole mount
RAB	Regulatory Asset Base
RMU	Ring Main Unit. A ground mounted switch used on underground distribution networks.
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCI	Statement of Corporate Intent
SF6	Sulphur Hexafluoride
SG	System Growth
Subtransmission	The lines and cables that connect zone substation and the GXP.
SWER	Single Wire Earth Return
SWGR	Switchgear
SSDG	Small Scale Distributed Generation
Tx	Transformer
Third party interference cause outages	All unplanned customer interruptions resulting from external contractors or members of the public and includes dig-in, overhead contact, vandalism, and vehicle damage
UG	Underground
UHF	Ultra-High Frequency

Unknown cause outages	All unplanned interruptions where the cause is not known
Vegetation cause outages	All unplanned customer interruptions resulting from vegetation contact, includes debris, grass and tree contact
VHF	Very High Frequency
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
Wildlife cause outages	All unplanned customer interruptions resulting from wildlife contact - includes birds, possums, vermin, cats etc

Appendix 2

Detailed Survey Results

Table 156: Summary of customer survey results[141]

Aspects	Conclusions from Survey
Importance of: • Keeping the power on; • Getting the power back on when it is off; • Keeping prices low.	• Industrial customers regarded keeping the power on all the time as most important, with getting the power back on quickly if it goes off as a clear second choice. The third choice has become dominated by keeping line charges low. • Gisborne mass-market customers regarded keeping the power on all the time as the most important. The second most important was mixed between getting the power back on quickly if it goes off and keeping line charges low. • Wairoa mass-market customers' responses are mixed, with a slight skew towards keeping the power on all the time. Second choice sees similarly mixed response, with keeping the power on as the highest response (suggesting confusion between continuity and restoration). Third choice was clearly keeping line charges low.
Performance of: • Keeping the power on; • Getting the power back on when its off; • Keeping prices low.	• Industrial customers had a range of views at how good Firstlight is at keeping the power on and getting the power back on, ranging from Excellent to Average with a skew towards Very Good. • Gisborne mass-market customers had a range of views on how well Eastland is keeping the power on, from Excellent to Average but with a skew towards Very Good. Similarly, there are a wide range of views on how well Firstlight is at keeping line charges low clustered around Average. • Wairoa mass-market customers' views on how well Firstlight is keeping the power on range from Excellent to Poor with a slight skew towards Very Good. Similarly, views on how well Eastland gets the power back on range from Excellent to Average with a skew towards Very Good. Views on keeping line charges low range from Excellent to Poor, with a slight skew towards Average.
Awareness of TOU pricing for domestic customers.	• There was a low awareness across all three market segments. • Industrial customers' awareness has increased slightly, but mass-market awareness has declined.
Likely timeframe to electrify industrial process heating or home energy use.	• Interest in electrifying industrial process heat was low. • Interest in electrifying home energy use was also low.
Changing retailers.	• Most large industrial customers' have changed retailer either 2 to 5 years ago, or not at all. • Most Gisborne mass-market customers' have not changed retailers within the last 2 years. • Wairoa mass-market customers are spread but with a skew towards more than 5 years ago.
Ability to alter consumption patterns	• Most of the large industrial customers could only shift their consumption to off-peak periods with a lot of difficulty. Common themes were that most of their load is chilling (and is therefore already 24 hours) of that they operate 2 and 3 shifts during harvest seasons. • Both the Gisborne and Wairoa mass-markets showed a slight skew towards being able to easily shift consumption, which might merit a more targeted study.
Likely installation of rooftop solar panels.	• Large customers appear very unlikely to install rooftop solar at their plant within the next 5 years. • Both the Gisborne and Wairoa mass-markets have definite skewed towards Never installing rooftop solar, however some further study of those who indicated some willingness might be merited.
Likely purchase of an electric car.	• Interest in buying an EV amongst large customers (presumably as an office run-about) was high across all timeframes. • Similar to the 2020 and 2021 surveys, both the Gisborne and Wairoa mass markets have a definite skew towards Never buying an electric car.
Likely installation of a battery	• Large customers' views are evenly spread across all timeframes. • The Gisborne mass-market has an even spread from 2 to 5 years to Never. • The Wairoa mass market has a definite skew towards either 5 to 10 years or never installing a battery.

[141] The survey was conducted whilst still under the ownership of Eastland Group, results summary has been updated to reflect the change of ownership to Firstlight

Appendix 3

Progress on reliability improvement recommendation included in the 2021 AMP

Table 157: Summary of customer survey results

Cause of unreliability	Status as at end-FY2023	Actions planned for FY2024
1. It is clear that feeder security levels have a direct impact into the reliability of a feeder. It is recommended that a memo (or study) be completed to look at whether viable network extensions can be established to minimise impacts of adverse weather events on our vulnerable feeders. If back-up/secondary supply is not an option, viability options on a permanent diesel generator be completed.	A study was done to review possible extensions or new installations on the network to address feeder security levels. The findings of that review are discussed below: • Convert the GIS-TOKO 110kV line to 50kV to provide a 2nd supply to the coast. The line will connect at the Tokomaru Bay substation and supply the Ruatoria and Te Araroa Subs. The existing GIS-TOL 50kV will be normal open at Tokomaru Bay Sub and supply the Tolaga and Tokomaru Bay Sub. • A project has been developed to build a new 11kV substation near Gisborne Sub which will supply the surrounding areas. This will reduce customers on some of the long town feeders and decrease the demand from the Kaiti, Port and Makaraka Substations.	The GIS-TOKO conversion was completed during FY2022, it has been essential in helping reduce both SAIDI & SAIFI for the Coast Region. The two lines allow full back-feeding capabilities if faults occur on the GIS-TOL 50kV line.
2. A plan for the re-establishment of a generator on the Raupunga feeder is required. The significant increase in the SAIDI and SAIFI due to its absence shows the significant impact it can have on our quality targets.	There is a capital program planned to install the new generator during FY2026.	No change in delivery date. Install of new generator expected in FY2026
3. There is significant justification for the increased pole replacement program. Both the reliability analysis and pole inspection results are indicating the need for this work to be completed	The accelerated pole replacement program commenced during FY2022. Due to the major weather events in FY2023 some resources had to re-distributed and meant the target replacement rate was not meet during this period.	The program will continue during FY2024 with target areas identified for red tag pole replacements.
4. There has been sufficient failures on the bus coupler on oil insulated ground mount switchgear to warrant a remediation program. Failures have been occurring on both couplers between units and on the ends of the oil switchgear. It is recommended that a program be established to both replace the oil switchgear units (Units are obsolete) and during the process of this program, inspections and installation of Guroflex (Insulation – prevents flashover) be	It was planned to replace oil switchgear with ABB SF6 GM switchgear. There was defect identified with the proposed ABB gear which meant the replacement project was paused until a new replacement could be found. At present there was no alternative switchgear found which is suitable. The ABB defect can be managed so it was decided to continue replacing oil switchgear with the ABB SF6 units.	Oil switchgear replacement program to be continued during FY2024 with the ABB SF6 switchgear.

Cause of unreliability	Status as at end-FY2023	Actions planned for FY2024
completed to minimise the risk of these faults from occurring.		
5. Cable faults tend to be focussed on several urban feeders. While the replacement of the cables on the feeders wouldn't be viable (Given we cannot narrow down any causal reason) it is a recommendation that some sort of remote monitoring be used to reduce the response times to any unplanned faults i.e. cable mounted fault passage indicators.	Options to address cable fault monitoring have been discussed but no further progress has occurred. The first step will be to conduct a cost/benefit analysis and determine which feeders and switch gear will be the most optimal areas to install them in.	No plans yet to progress the install of cable mounted fault passage indicators.
6. Conductor faults are increasing on our network with ever increasing consequence. While inspections are not effective from the ground we are currently trialling a drone based inspection process which will be able to look at conductor more closely. It is recommended that the results of this inspection process be reviewed once complete and worst performing feeders (in terms of conductor failure) be schedule for inspection by drone.	An external contractor conducted a drone survey on the Ruakituri and Mahia feeders (both long rural feeder which traverses rugged and hilly farmland). The results proved beneficial with defects identified that may have been missed due to access issues and resource constraints.	The drone work was reviewed and considered a success in terms of inspection data and the ability to access remote sections of feeders. To be more effective in operating the drone it was suggested that analysis of long rural feeders with sections of line which are difficult to access be prioritised for drone inspection.
7. Third Party interference events are continuing. It is proposed that options for minimising these events be discussed at the AMC meeting given the difficult nature of rectifying these events.		

Appendix 4

Network Security and Capacity Assesment

Substation	Required security level	Transformer Capacity (MVA)	Supply Capacity (MVA)	Generator capacity (MW)	11kV back-up capacity (MVA)	Contingent capacity (MVA)	FY2020 Maximum Demand (MW)	FY2020 % installed capacity	FY2020 % cont. capacity	FY2020 Security OK	FY2031 Maximum Demand (MW)[142]	FY2031 % installed capacity	FY2031 % cont. capacity	FY2031 Security OK
Gisborne	A	2 x 60 (110/50kV)	120	6	n/a	60	49.89	42%	83%	Yes	52.71	44%	88%[143]	Yes
Te Araroa	C3	1 x 2.5	2.5	1	0.25	1.25	0.81	32%	65%	Yes	0.83	33%	66%	Yes
Ruatoria	C3	1 x 5.0/7.5	5	1	1	2	1.38	28%	69%	Yes	1.42	28%	71%	Yes
Tokomaru Bay	C3	1 x 2.5	2.5	0	1.2	1.2	1.01	40%	84%	Yes	1.03	41%	86%	Yes
Tolaga Bay	C3	1 x 1phase 5.0	5	1	0.8	1.8	1.23	25%	68%	Yes	1.26	25%	70%	Yes
Kaiti	C1	1 x 12.5	12.5	0	8	8	7.23	58%	90%	Yes	8.07	65%	101%[144]	No
Port	C1	1 x 12.5	12.5	0	8	8	6.38	51%	80%	Yes	6.74	54%	84% [13]	Yes
Carnarvon	B	2 x 12.5	25	0	11	23.5	13.53	54%	58%	Yes	14.29	57%	61%	Yes
Parkinson	B	2 x 12.5	25	0	11	23.5	10.16	41%	43%	Yes	10.73	43%	46%	Yes
Makaraka	C1	1 x 12.75	12.75	0	7	7	6.85	54%	98%	Yes	7.65	60%	109% [13]	No
Patutahi	C1	2 x 1phase	5	0	5	5	3.15	63%	63%	Yes	3.33	67%	67%	Yes
Pehiri	C3	1 x 2.5	2.5	0	1.25	1.25	0.54	22%	43%	Yes	0.54	22%	43%	Yes
Ngatapa	C3	1 x 2.5	2.5	0	1.5	1.5	0.47	19%	31%	Yes	0.47	19%	31%	Yes
Puha	C2	1 x 1phase 5.0	5	1	0.5	1.5	2.12	42%	141%	Yes	2.12	42%	141%[145]	No
JNL	C1	1 x 12.75	12.75	0	5	5	2.40	19%	48%	Yes	2.40	19%	48%	Yes
Matawhero	B	2 x 12.5	25	0	5	17.5	4.40	18%	25%	Yes	4.91	20%	28%	Yes
Tuai	D	1 x 1 ph 5	6	0	0	0	0.62	10%	0%	Yes	0.59	10%	0%	No
Wairoa	B	2 x 1 ph 10	20	5	n/a	12.5	9.60	48%	77%	Yes	9.81	49%	78%	Yes
Wairoa-		1 x 12.5 (11/33)	12.5	1	0	1	1.83	15%	183%	Yes	2.11	17%	211%	Yes
Kiwi	C2	1 x 6.5 (11/50)	6.5	0	0	0	4.53	70%	-	Yes	4.53	70%	-	Yes
Blacks Pad	C3	1 x 1.5 (33/11)	1.5	1	0.5	1.5	1.70	113%	113%	No	2.11	141%	141%[146]	No
Tahaenui	C3	1 x 1.5 (33/11)	1.5	0	2	2	0.72	48%	36%	Yes	0.72	48%	36%	Yes
Waihi	C2	1 x 6.5 (50/11)	6.5	0	0	0	4.53	70%	0%	Yes	4.53	70%	0%	Yes

142 Excluding the prudent planning margin
143 Capacity constraint solution – Tuai-Gis Line upgrade and 50kV capacitor bank installs
144 Capacity constraint solution – Installation of Massey substation
145 Capacity constraint solution – Ngatapa-Puha 11kV link project
146 Capacity constraint solution – Extension of the 33kV line and relocation of the Blacks Pad substation

Appendix 5

Additional Disclosures

Notice of planned and unplanned interruptions

In order to ensure the safety and reliability of the electricity supply, there will be occasions where it becomes necessary to isolate specific segments of the network for maintenance purposes. In the case of planned outages, Firstlight follows a protocol of notifying retailers in advance. Additionally, this information is made available on the Firstlight website, disseminated through local newspapers, radio stations, and communicated to Ngāti Porou.

Firstlight's connection agreements stipulate a minimum notice period of 48 hours for planned interruptions, (excluding load-control) will be provided.

Unplanned interruptions are not published.

Practices for managing voltage quality

Presently, the Firstlight's protocol for addressing low voltage issues is initiated upon notification by the customer. Firstlight does not undertake proactive checks.

Where an issue is confirmed a project is initiated to resolve. In some circumstances the issue arises due to customer increasing their load. In this case the resolution may require customer involvement and contribution to any network upgrade. Any necessary outages to rectify the issue are planned through the established outage planning and notification processes.

In instances where the issue is intermittent, data loggers are commonly deployed within the network infrastructure to monitor voltage levels. These data loggers facilitate the collection of network data, enabling personnel to systematically track the occurrence and nature of the issue for the purpose of rectification.

We will be investigating using smart meter data to proactively assess voltage. We will update progress on this in future AMPs.

A Description of customer service practices

Firstlight conducts an annual customer survey aimed at gauging customer perspectives on various aspects, including supply reliability, pricing, demand management, and flicker. The 2022 survey involved the participation of the 25 largest industrial customers and a random sample comprising 597 mass market customers.

The results of this survey, along with the associated metrics, are detailed in section 6. Our customer service targets are included in Section 8.

In regard to customer complaints, Firstlight is committed to swift and satisfactory resolution of any concerns raised. Our website offers information outlining the procedural steps and expected response times for addressing and resolving customer complaints. Additionally, the customer agreements in place also document this process.

https://www.firstlightnetwork.co.nz/tell-me-about/firstlight-network/disputes/

Practices for connecting new customers and altering existing connections

Detailed information regarding the network connection process is accessible via the Firstlight website. This resource includes proforma documents designed to streamline and simplify the connection procedure.

The connection agreement, accessible online, outlines the customer's responsibility for covering the costs associated with new or modified connections. In the case of sub-divisions, developers are typically tasked with bearing these costs, with the potential for ownership to be transferred to Firstlight, contingent upon adherence to the requisite standards.

Under normal circumstances, connections are expected to be completed within a 21-day notice period. However, it's important to note that, depending on the specific connection requirements, this timeline may not always be feasible. Effective communication will be facilitated through the contact details provided in the connection application form.

When introducing new customers to our network, all work must conform to the prescribed electrical standards. The Firstlight website offers a list of approved contractors who may be engaged to perform network-related tasks. These contractors determine project costs in accordance with their established pricing structures, affording customers the flexibility to select from multiple options and ensure competitive pricing among contractors.

Firstlight enables a competitive market for new connection work. The competitive market is our approach to minimise connection costs to customers.

Refer also to Section 10.5.

New Connections likely to have a significant impact on the network operations or asset management practices

Presently we do not have any new connections that are likely to have a significant impact on network operations or asset management practices.

Our demand forecasts and system development planning include provision for major customer upgrades via our prudent planning margin. This is our approach to managing the risk associated with the uncertainty of new demand. This is described in more detail in Sections 10.4, 10.4.3 and 10.4.5.

How the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network is assessed through the application of our planning criteria and development planning as described in Section 10.3. These cover capacity, security, reliability, voltage and location and are applied where a new significant connection application is made. Section 10.3.3 and 10.3.4 describes our approach for considering new distributed generation.

Timing for new significant demand is considered during the planning phase. Our approach is to install capacity ahead of demand to avoid the risk of non-supply of new load. However, projects do no commence until the customer has signed the required connection agreement and paid any customer contribution that may be required.

Innovation practices

Firstlight is committed to the adoption of proven innovative practices while recognising that it may not always be at the forefront of industry leadership in this regard. The primary focus of the organisation is to maintain cost efficiency, taking into consideration the socio-economic conditions prevalent in the region.

Most recent examples of embracing established innovation practices includes the implementation of an off-grid solution in the remote Raukūmara Range and the utilization of drones for inspecting poles, lines, and conductors. Firstlight's approach typically prioritizes the adoption of tried-and-tested innovation solutions, thereby significantly increasing the likelihood of successful outcomes. The decision to continue with a particular practice is contingent upon the achievement of objectives during the scoping phase and a careful balancing of the associated deployment costs.

Firstlight actively monitors industry developments to stay informed about emerging innovation practices adopted by other Electricity Distribution Businesses (EDBs). We actively encourage our staff to attend industry conferences to remain up-to-date with the evolving landscape of our sector.

Example Innovative Practices:

- Base Power Standalone Power System: Firstlight successfully installed a Base Power standalone power system in a remote area beyond the Tarndale slip in the Raukūmara Ranges, one of the most challenging terrains in the region. The decision to transition a property off the grid is a significant one, necessitating a thorough evaluation of the off-grid solution against traditional network infrastructure. The implemented solution integrates a solar array with a sophisticated smart energy management system and a backup generator to ensure both customer satisfaction and network reliability. Base Power collaborated closely with Firstlight to tailor a customized plan, optimize required assets, and enhance the network team's expertise in solar and battery storage installations. Beyond hardware, the system incorporates features such as solar forecasting and real-time system status sharing through embedded communication devices, benefiting customers and line crews alike. This project exemplifies how off-grid and non-network solutions can support strategic maintenance and line upgrades in critical locations.
- Drone UAV Inspections: Covering an extensive 12,000 square kilometers of often remote and challenging terrain, Firstlight's network necessitates regular inspections of poles, lines, and conductors as part of its ongoing asset management program. In March 2022, Firstlight introduced drone (unmanned aerial vehicle) inspections, significantly enhancing efficiency in covering vast areas. The data collected through drone inspections is subsequently employed for planning upgrades and replacements.
- Earth Fault Pickup Alarms: Over the past two years, Firstlight Network has systematically integrated earth fault pick-up alarms into its Supervisory Control and Data Acquisition (SCADA) system. This capability enables proactive responses to potential conductor contact issues, facilitating early identification of problems such as tree/clashing interference or emerging insulator failures. Initially initiated in response to vegetation-related challenges, this project has also proven beneficial in mitigating other outage causes through early fault detection. To further our monitoring capabilities, we have invested in the Acselerator TEAM software, automating data collection from multiple remote devices. This software, in conjunction with SCADA, enhances our ability to actively monitor remote relays and analyse data trends

Appendix 6

Reconciliation to information disclosure requirements

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
Summary			
3.1	The AMP must include a summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant.	1	
Background and Objectives			
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes	2.6, 2.8, 7	
Purpose Statement			
3.3	The AMP must include a purpose statement that:		
3.3.1	Makes the status of the AMP clear.	2.1.1, 2.1.4	
3.3.2	States the corporate mission or vision as it relates to asset management	5	
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process	2.8	
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management	2.8	
Planning Period			
3.4	The AMP must state that the period covered by the plan is 10 years or more from the commencement of the financial year.	2.1.3	
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	2.1.4	
Stakeholder Interests			
3.6	The AMP must identify the EDB's important stakeholders and indicate:	5.4	
3.6.1	How the interests of stakeholders are identified;	5.4	
3.6.2	What these interests are;	5.4	
3.6.3	How these interests are accommodated in the EDB's asset management practices: and	5.4	
3.6.4	how conflicting interests are managed.	5.4	
Accountabilities and Responsibilities for Asset Management			
3.7.1	The AMP must describe the extent of Board approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to the Board.	2.5	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
3.7.2	At the executive level, the AMP must provide an indication of how the in-house asset management and planning organisation is structured.	2.4, 2.5	
3.7.3	At the field operations level, the AMP must comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	2.4, 2.5, 13.5	
Significant Assumptions and Uncertainties			
3.8	The AMP must identify significant assumptions, which must:		
3.8.1	Be quantified where possible.	2.9, and throughout the document	
3.8.2	Be clearly identified in a manner that makes their significance understandable to interested persons including:	2.9, and throughout the document	
3.8.3	Include a description of the changes proposed where the information is not based on the EDB's existing business.	2.9	
3.8.4	Identify the sources of uncertainty and the potential effect of the uncertainty on the prospective information.	2.9, and throughout the document	
3.8.5	Include the price inflator assumptions used to prepare the information in Schedules 11a and 11b.	2.9	
3.9	Include a description of the uncertainties that may lead to changes in future disclosures.	2.9, and throughout the document	
Asset Management Strategy and Delivery			
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	7, 13	
Asset Management Data			
3.11	To support the AMMAT disclosure, the AMP must include an overview of the processes for managing asset management data; and	9.3, 9.4, 11.3	
3.12	A statement covering any limitations on the availability and completeness of asset management data and disclosure of initiatives intended to improve the quality of this data.	9.3, 9.4	
Asset Management Process			
3.13	The AMP must include a description of the processes used for:	-	
3.13.1	Managing routine asset inspections and network maintenance;	2.6, Throughout section 0	
3.13.2	Planning and implementing network development projects; and;	2.6, 10.3	
3.13.3	Measuring network performance.	0, 8.5, 8.6	
Asset Management Documentation, Controls and Review Processes			

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
3.14	To support the AMMAT disclosure, the AMP must include an overview of asset management documentation, controls, and review processes.	2.8, 13.1, 13.3, 13.4	
Assets Covered			
4.1	High Level Description of the Distribution Area	3.1	
4.1.1	The high-level description of the distribution area must include: - the regions covered;	3.1	
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities;	3.1, 4	
4.1.3	Description of the load characteristics for different parts of the network; and	4.1 to 4.11	
4.1.4	The peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.	10.4	
4.2	Description of the network configuration, including;		
4.2.1	Identification bulk electricity supply points and any distributed generation with a capacity greater than 1 MW;	3.4	
4.2.2	The existing firm supply capacity and current peak load at each bulk supply point, including the capacity of zone substations and the voltage(s) of the sub-transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub-transmission security or by providing alternative security class ratings;	10.6	
4.2.3	A description of the distribution system including the extent to which it is underground;	3.6, 11.9.	
4.2.4	A brief description of the network's distribution substation arrangements;	3.6, 11.10,11.11	
4.2.5	A description of the low voltage network, including the extent to which it is underground; and	3.6.6, 11.21	
4.2.6	An overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.	3.7, 11.19, 11.20	
4.4	Description of network assets by category, which includes information for the following areas;		
4.4.1	Voltage levels	3.2, and 11.6 to 11.21 (part of the lifecycle plans)	
4.4.2	Description and quantity of assets;	11.6 to 11.22 (part of the lifecycle plans)	
4.4.3	Age profiles; and	4.7, 11.6 to 11.22 (part of the lifecycle plans)	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
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.	11.6 to 11.22 (part of the lifecycle plans)	
4.5	The asset categories must at least include the following;		
4.5.1	Sub-transmission	11.7, 11.8	
4.5.2	Zone Substations	11.10, 11.11, 11.17	
4.5.3	Distribution and LV Lines	11.8, 11.21	
4.5.4	Distribution and LV cables	11.9, 11.21	
4.5.5	Distribution substations and transformers	11.12,11.13, 11.14	
4.5.6	Distribution switchgear	11.13, 11.15, 11.16	
4.5.7	Other system fixed assets	11.18, 11.19, 11.20	
4.5.8	Other assets	11.21	
4.5.9	Assets installed at bulk supply points owned by others	3.3	
4.5.10	Mobile substations and generators whose function is to increase supply reliability or reduce demand	11.22	
4.5.11	Other generation plants.	3.4	
Service Levels			
5.0	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.	8	
6.0	Performance indicators for which targets are defined must include SAIDI and SAIFI values for the next 5 disclosure years.	8.4	
7.0	Performance indicators for which targets are defined should also include:		
7.1	Consumer orientated service targets that preferably differentiate between different consumer types	8.4.4	
7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	8.5	
8.0	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 stakeholder's requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	8 (commented on throughout section)	
Network Development Planning			
11.1	The AMP must include a description of network development plans, including: A description of the planning criteria and assumptions for network development	10.3	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
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	13.1	
11.5	A description of strategies or processes (If any) used by the EDB that promote the energy efficient operation of the network	10.3.7	
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	10.3	
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	10.3	
11.8	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand.	10.4	
11.8.1	Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	10.4	
11.8.2	Discuss how uncertain but substantial individual projects/developments that affect load are considered in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	10.4	
11.8.3	Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	10.6, Appendix 4	
11.8.4	Discuss the impact on the load forecast of any anticipated levels of distributed generation in a network, and the projected impact of any demand side management.	10.4.3	
Network Development Plan			
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;	10.6.1 – 10.9	
11.9.1	The reasons for choosing a selected option for projects where decisions have been made;	10.3.8, 10.6.1, 10.6,10.7,10.8 10.9.14, 10.10,10.12	
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	10.3.3, 10.3.5, 10.3.6,10.3.7, 10.80, ,	
11.9.3	Considerations of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	10.3.3 10.3.4, 10.3.5,10.3.6, 10.3.7, 10.9.14	
11.10.1	The network development plan must include: 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.	10.6.1,10.6.2,10.7, 10.9.7, 10.9.14, 10.10	
11.10.2	A summary description of the programmes and projects planned for the following four years (where known); and	10.6.1,10.6.2,10.7, 10.9.7, 10.9.14, 10.10	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period.	10.6.1,10.6.2,10.7, 10.9.7, 10.9.14, 10.10	
11.11	The AMP must include 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	10.3.3, 10.3.4	
11.12	A description of the EDB's policies on non-network solutions, including:	10.3.6, 10.8	
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;	10.3.3, 10.3.4, 10.3.6,	
11.12.2	The potential for non-network solutions to address network problems or constraints.	10.3.3, 10.3.4, 10.3.6, 10.8	
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12.0	The AMP must provide a detailed description of the lifecycle assets management processes, including:		
12.1	The key drivers for maintenance planning and assumptions;	11.3 to 11.23 (part of the lifecycle plans)	
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;	11.3 to 11.23 (part of the lifecycle plans)	
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;	11.3 to 11.23 (part of the lifecycle plans)	
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	11.3 to 11.23 (part of the lifecycle plans)	
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period;	11.3 to 11.23 (part of the lifecycle plans)	
12.3	Identification of the asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include:	11.3 to 11.23 (part of the lifecycle plans)	
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	11.3 to 11.23 (part of the lifecycle plans)	
12.3.2	A description of innovations that have deferred asset replacements;	11.3 to 11.23 (part of the lifecycle plans)	
12.3.3	A description of the projects currently underway or planned for the next 12 months;	11.3 to 11.23 (part of the lifecycle plans)	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
12.3.4	A summary of the projects planned for the following four years (where known); and	11.3 to 11.23 (part of the lifecycle plans)	
12.3.5	An overview of other work being considered for the remainder of the AMP planning period; and	11.3 to 11.23 (part of the lifecycle plans)	
12.5	Identification of the approach used for developing capital expenditure projections for lifecycle management	6.3.2, 6.4, 7.3, 11.3,	
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	11.23.4 – 11.23.6	
12.7	The EDB's consideration of non-network solution 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	10.3.3, 10.3.4, 10.3.6 11.23 Table 2	
Non-Network Development, Maintenance and Renewal			
13.0	The AMP must provide a summary description of material non-network development, maintenance and renewal plans including:		
13.1	A description of non-network assets;	9.3, 9.8	
13.2	Development, maintenance and renewal policies that cover them;	9.3, 9.8	
13.3	A description of material capital expenditure projects (where known) planned for the next five years; and	9.8	
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	9.8	
Risk Management			
14.0	The AMP must provide details of risk policies and assessment and mitigation including:		
14.1	Methods, details and conclusions of risk analysis;	12	
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;	12.5	
14.3	A description of the policies to mitigate or manage the risks of events identified in clause 14.2; and	12.5.3	
14.4	Details of emergency response and contingency plans.	12.6	
Evaluation of Performance			
15.0	AMP's must provide details of performance measurement, evaluation, and improvement, Including:		
15.1	A review of progress against plan, both physical and financial;	8.4.1, 8.7, 14, Appendix 2, Appendix 3	
15.2	An evaluation and comparison of actual service level performance against targeted performance;	6.3, 6.4	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
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.	1.6.1, 9.2.2,9.2.4, appendix 6	
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.	9,	
Capability to Deliver			
16.0	The AMP 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	13.5	
16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.4, 2.5	
17.1	A description of how the EDB provides notice to and communicated with consumers regarding planned interruptions and unplanned interruptions, including any changes to the EDB's processes and communications in respect of planned and unplanned interruptions;	Appendix 5 Contents Page hyperlink	
17.2	A description of the EDB's practices for monitoring voltage	Appendix 5	
Customer Services Practices			
17.3.1	The EDB's customer engagement protocols and customer service measure – including customer satisfaction with the EDB supply of electricity distribution services	6.3 Appendix 5	
17.3.2	The EDB's approach to planning and managing customer complaint resolution	Appendix 5 Contents Page hyperlink	
17.4	A description of the EDB's practices for connecting consumers	Appendix 5 Contents Page hyperlink	
17.4.1	The EDB's approach to planning and management of connecting new customers, and overcoming commonly encountered issues	Contents Page hyperlink	
17.4.2	How the EDB is seeking to minimise the cost to consumers of new or altered connections	Appendix 5	
17.4.3	The EDB's approach to planning and managing communication with consumers about new or altered connections	Appendix 5	
17.4.4	Commonly encountered delays and potential timeframes for different connections.	Appendix 5 Contents Page hyperlink	
17.5.1	A description of how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network	Appendix 5 10.3, 10.3.3, 10.4, 10.4.3, 10.4.5	

Determination Clause Reference	Requirement	AMP Reference Section	Commentary
17.5.2	How the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity	Appendix 5 10.6	
Innovation practices			
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.	Appendix 5	
17.6.2	The EDB's desired outcome of any innovation practices and how they may improve outcomes for consumers	Appendix 5	
17.6.3	How the EDB measures success and makes decision regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices	Appendix 5	
17.6.4	How the EDB's decision making, and innovation practices depend on the work of other companies, including other EDB's and providers of non-network solutions	Appendix 5	
17.6.5	The types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking the information	Appendix 5	

Appendix 7

List of schedules included

Outlined below is a list of the attached schedules which complement the asset management plan.

Schedule 11a – Report on Forecast Capital Expenditure

Schedule 11b – Report on Forecast Operational Expenditure

Schedule 12a – Report on Asset Condition

Schedule 12b – Report on Forecast Capacity

Schedule 12c – Report on Forecast Network Demand

Schedule 12d – Report on Forecast Interruptions and Duration

Schedule 13 – Report on Asset Management Maturity

COMMERCE COMMISSION
NEW ZEALAND

Electricity Distribution Information Disclosure
(Non-material) Amendment Determination [2023] NZCC 6
Schedules 11a–13

Company Name	Firstlight Network
Disclosure Date	1 October 2023
AMP Planning Period Start Date (first day)	1 April 2023

27 April 2023

Table of Contents

Information disclosure asset management plan schedules

Disclosure Template Instructions

This document forms Schedules 11a–13 to the Electricity Distribution Information Disclosure (Non-material) Amendment Determination [2023] NZCC 6.

The Schedules take the form of templates for use by EDBs when making disclosures under subclauses 2.6.1(1)(d), 2.6.1(1)(e), 2.6.1(2), 2.6.5(6), 2.6.6(1) and 2.6.6(2) of the Electricity Distribution Information Disclosure Determination 2012. The EDB may include a completed Schedule 13: Report on Asset Management Maturity table with its disclosures made under subclause 2.6.6(1) and 2.6.6(2), but this is not required. Schedule 13 tables that are not completed should be removed from disclosures made under subclause 2.6.6(1)

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the first day of the 10 year planning period should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (planning period start date) is used to calculate disclosure years in the column headings that show above some of the tables. It is also used to calculate the AMP planning period dates in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to guard against errors in data entry, some data entry cells test entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names or to values between 0% and 100%. Where this occurs, a validation message will appear when data is being entered.

Conditional Formatting Settings on Data Entry Cells

Schedule 12a columns G to K contains conditional formatting. The cells will change colour if the row totals do not add to 100%.

Inserting Additional Rows

The schedule 11a, 12b and 12c templates may require additional rows to be inserted in tables marked 'include additional rows if needed'.
Additional rows must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
For schedule 12b the formula for column J (Utilisation of Installed Firm Capacity %) will need to be copied into the inserted row(s).
Column A schedule references should not be entered in additional rows.

Description of Calculation References

Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook. Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

Changes Since Previous Version

Refer to the Targeted Information Disclosure Review - Electricity Distribution Businesses Final reasons paper - Tranche 1, for the details of changes made. A summary is provided in Chapter 2.

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8													
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	82	141	124	131	138	145	153	163	172	180	194
11		System growth	2,690	1,274	1,892	2,923	4,837	5,546	4,653	1,820	4,164	7,548	3,296
12		Asset replacement and renewal	11,670	12,594	12,274	13,278	9,803	12,093	11,755	15,523	12,460	13,322	12,868
13		Asset relocations	-	51	54	57	59	62	64	67	70	72	76
14		Reliability, safety and environment:											
15		Quality of supply	705	203	1,835	1,414	2,562	106	1,417	69	739	339	356
16		Legislative and regulatory	4	184	202	39	42	45	23	24	25	26	27
17		Other reliability, safety and environment	9	191	144	202	1,124	155	1,046	-	1,137	-	1,237
18		**Total reliability, safety and environment**	718	578	2,182	1,654	3,727	305	2,486	93	1,901	364	1,620
19		**Expenditure on network assets**	15,160	14,638	16,525	18,043	18,564	18,152	19,112	17,666	18,767	21,485	18,053
20		Expenditure on non-network assets	64	311	270	656	294	307	320	334	348	359	377
21		**Expenditure on assets**	15,224	14,949	16,796	18,699	18,859	18,459	19,431	18,000	19,114	21,844	18,430
22													
23	*plus*	Cost of financing	152	149	168	187	189	185	194	180	191	218	184
24	*less*	Value of capital contributions	-	-	-	-	-	-	-	-	-	-	-
25	*plus*	Value of vested assets	500	500	500	500	500	500	500	500	500	500	500
26													
27		**Capital expenditure forecast**	15,876	15,598	17,464	19,386	19,547	19,144	20,125	18,680	19,805	22,563	19,114
28													
29		Assets commissioned	16,078	15,626	17,277	19,194	19,531	19,184	20,027	18,824	19,693	22,287	19,459
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31													
32			**$000 (in constant prices)**										
33		Consumer connection	82	140	117	118	119	121	122	125	126	128	131
34		System growth	2,690	1,274	1,783	2,626	4,178	4,607	3,716	1,398	3,075	5,360	2,249
35		Asset replacement and renewal	11,670	12,592	11,576	11,929	8,472	10,045	9,387	11,924	9,200	9,458	8,783
36		Asset relocations	-	51	51	51	51	51	51	51	51	51	52
37		Reliability, safety and environment:											
38		Quality of supply	705	203	1,731	1,270	2,215	88	1,132	53	546	240	243
39		Legislative and regulatory	4	183	190	35	36	37	18	18	18	18	18
40		Other reliability, safety and environment	9	191	136	181	970	129	836	-	839	-	844
41		**Total reliability, safety and environment**	719	578	2,057	1,486	3,221	253	1,986	71	1,403	259	1,106
42		**Expenditure on network assets**	15,160	14,636	15,585	16,210	16,041	15,078	15,263	13,568	13,856	15,256	12,321
43		Expenditure on non-network assets	64	311	255	589	254	255	255	256	256	255	258
44		**Expenditure on assets**	15,224	14,946	15,840	16,799	16,295	15,333	15,518	13,825	14,112	15,510	12,579
45													
46		**Subcomponents of expenditure on assets (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)*											
47		Energy efficiency and demand side management, reduction of energy losses											
48		Overhead to underground conversion											
49		Research and development											
50		Cybersecurity (Commission only)											
51													

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
53													
54		**Difference between nominal and constant price forecasts**	**$000**										
55		Consumer connection	-	0	7	13	19	25	31	39	45	52	62
56		System growth	-	(0)	109	297	659	939	937	422	1,089	2,188	1,047
57		Asset replacement and renewal	-	2	697	1,349	1,331	2,048	2,368	3,600	3,260	3,863	4,085
58		Asset relocations	-	(0)	3	6	8	11	13	16	19	21	24
59		Reliability, safety and environment:											
60		Quality of supply	(0)	0	104	144	347	18	285	16	193	98	113
61		Legislative and regulatory	-	0	12	4	6	7	5	6	7	7	9
62		Other reliability, safety and environment	-	(0)	8	21	153	26	210	-	298	-	393
63		**Total reliability, safety and environment**	(0)	0	124	168	506	52	500	22	498	106	514
64		**Expenditure on network assets**	(0)	2	940	1,833	2,523	3,074	3,848	4,098	4,910	6,230	5,732
65		Expenditure on non-network assets	-	1	16	67	40	52	65	77	92	104	120
66		**Expenditure on assets**	(0)	2	956	1,900	2,563	3,126	3,913	4,175	5,002	6,334	5,851
67													
68		**Commentary on options and considerations made in the assessment of forecast expenditure**											
69		*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*											
70													
71													

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
72			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73		**11a(ii): Consumer Connection**						
74		*Consumer types defined by EDB**	**$000 (in constant prices)**					
75		Residential	17	59	58	59	61	62
76		Commercial	65	82	58	58	58	59
77		Industrial		-	-	-	-	-
78								
79								
80		**include additional rows if needed*						
81		**Consumer connection expenditure**	82	140	117	118	119	121
82	*less*	Capital contributions funding consumer connection						
83		**Consumer connection less capital contributions**	82	140	117	118	119	121
84		**11a(iii): System Growth**						
85		Subtransmission	1,826	539	760	1,241	3,207	3,216
86		Zone substations	-	-	157	520	104	523
87		Distribution and LV lines	790	352	398	397	397	398
88		Distribution and LV cables	-	227	250	250	250	251
89		Distribution substations and transformers	73	157	219	219	219	219
90		Distribution switchgear	-	-	-	-	-	-
91		Other network assets	-	-	-	-	-	-
92		**System growth expenditure**	2,690	1,274	1,783	2,626	4,178	4,607
93	*less*	Capital contributions funding system growth						
94		**System growth less capital contributions**	2,690	1,274	1,783	2,626	4,178	4,607
95								

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

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sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
97								
98	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
99		Subtransmission	1,750	2,051	1,687	2,413	1,115	1,128
100		Zone substations	703	688	578	811	364	564
101		Distribution and LV lines	7,869	7,805	7,127	5,703	5,397	5,725
102		Distribution and LV cables	209	238	268	268	268	269
103		Distribution substations and transformers	377	573	435	626	606	607
104		Distribution switchgear	548	545	502	501	501	503
105		Other network assets	214	692	979	1,608	221	1,250
106		**Asset replacement and renewal expenditure**	11,670	12,592	11,576	11,929	8,472	10,045
107	*less*	Capital contributions funding asset replacement and renewal						
108		**Asset replacement and renewal less capital contributions**	11,670	12,592	11,576	11,929	8,472	10,045
109								
110			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
111								
112	**11a(v): Asset Relocations**							
113		*Project or programme**	**$000 (in constant prices)**					
114		Asset relocations for Territorial authorities		51	51	51	51	51
115								
116								
117								
118								
119		**include additional rows if needed*						
120		All other project or programmes - asset relocations						
121		**Asset relocations expenditure**	-	51	51	51	51	51
122	*less*	Capital contributions funding asset relocations						
123		**Asset relocations less capital contributions**	-	51	51	51	51	51
124								
125			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
126								
127	**11a(vi): Quality of Supply**							
128		*Project or programme**	**$000 (in constant prices)**					
129		SCADA Rural Automation -development	-	-	35	35	-	36
		Comms Fibre Cable Gisborne Sub to Kaiti	-	-	-	64	-	-
		SCADA Master Station Development	59	6	10	10	10	10
		Generator purchase (350kVA Container)	467	90	-	-	-	-
		SCADA Switching & Outage Management System	-	-	522	1,041	1,042	-
130		New Generators - Security of Supply - 780kVA	-	-	1,044	-	1,042	-
131		11kV Field Recloser Automation Plan - additions	26	42	42	42	42	42
132		110kVa generator trailer and install	-	65	-	-	-	-
		Mahia Gneset - Muffler Replacement	27					
		Ruatoria Genset - Radiator Replacement	39					
		Te Araroa Genset Radiator Rebuild	33					
		Tolage Bay Genset - Radiator Rebuild	34					
		Gen 1 Te Araroa	20					
		Protection Upgrade - 50kV reclose and earthing		-	78	78	78	-
133								
134		**include additional rows if needed*						
135		All other projects or programmes - quality of supply						
136		**Quality of supply expenditure**	705	203	1,731	1,270	2,215	88
137	*less*	Capital contributions funding quality of supply						

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

sch ref							
138	**Quality of supply less capital contributions**	705	203	1,731	1,270	2,215	88
139							
141							

142 11a(vii): Legislative and Regulatory

sch ref	*Project or programme**	$000 (in constant prices)					
143							
144	AUFLS/ Protection Relay install		173	172	-	-	-
145	Replace Vehicle RTs		10	18	18	18	18
146	Mount		-	-	17	18	19
147							
148							
149	**include additional rows if needed*						
150	All other projects or programmes - legislative and regulatory	4	-	-	-	-	-
151	**Legislative and regulatory expenditure**	4	183	190	35	36	37
152	*less* Capital contributions funding legislative and regulatory						
153	**Legislative and regulatory less capital contributions**	4	183	190	35	36	37
154							
155		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*

156 11a(viii): Other Reliability, Safety and Environment

sch ref	*Project or programme**	$000 (in constant prices)					
157							
158	Replace Galv Meter Box (Asbestos)	9	31	31	31	-	-
159	Replace Galv Meter Box (Safety) - WAIROA		-	104	104	104	105
	Replace 11kV SWGR Tokomaru Bay,Matawhero,Kaiti,Kiwi & Parkinson.		89	-	-	834	-
	Zone Substation Tolaga Bay, Puha Install Sepa Units		71	-	-	-	-
	Zone Substation Install Air Conditioning Units (Parkinson,Kaiti)(Patutahi)		-	-	9	9	9
160	Zone Substation Painting Internal Block Walls (Te Araroa, Tokomarau Bay)		-	-	7	8	-
161	Zone Substation Carnarvon Replacement Cast Cable Box Replacement		-	-	15	-	-
162	Switching Station Building Painting/Door Replacements (Reads, Apark, Bright)		-	-	15	15	15
163	**include additional rows if needed*						
164	All other projects or programmes - other reliability, safety and environment						
165	**Other reliability, safety and environment expenditure**	9	191	136	181	970	129
166	*less* Capital contributions funding other reliability, safety and environment						
167	**Other reliability, safety and environment less capital contributions**	9	191	136	181	970	129
168							
169		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
170							

171 11a(ix): Non-Network Assets

sch ref							
172	**Routine expenditure**						
173	*Project or programme**	$000 (in constant prices)					
174	General building capex (ENL office, Eastech, Wairoa Depot)	1	107	21	21	21	21
175	Vehicle Replacement @ $60k each (Ntk)		130	136	135	136	136
176	additional/upgrade)	32	29	29	29	29	29
177	General asset replacement (Ntk)	(1)	23	23	23	23	23
	IS Hardware	-	22	46	46	46	46
178	Diesel Tanker Trailer	24	-	-	-	-	-
179	**include additional rows if needed*						
180	All other projects or programmes - routine expenditure						
181	**Routine expenditure**	56	311	255	254	254	255
182	**Atypical expenditure**						
183	*Project or programme**						
184	Property Capital Projects Wairoa office rebuild	8	-	-	335	-	-
185							
186							
187							
188							
189	**include additional rows if needed*						
190	All other projects or programmes - atypical expenditure						
191	**Atypical expenditure**	8	-	-	335	-	-
192							
193	**Expenditure on non-network assets**	64	311	255	589	254	255
194							

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	3,015	2,615	3,261	3,429	3,562	3,703	3,854	4,007	4,169	4,331	4,511
11	Vegetation management	1,021	1,636	1,743	1,840	1,916	1,989	2,069	2,152	2,238	2,328	2,422
12	Routine and corrective maintenance and inspection	1,554	3,059	3,086	3,071	3,408	3,319	3,717	3,634	3,915	3,857	4,278
13	Asset replacement and renewal	573	859	906	883	926	972	585	608	632	658	684
14	**Network Opex**	6,162	8,169	8,997	9,223	9,811	9,982	10,226	10,401	10,954	11,174	11,895
15	System operations and network support	2,053	2,264	3,172	3,362	3,531	3,672	3,819	3,971	4,130	4,296	4,467
16	Business support	4,679	4,000	4,349	4,610	4,840	5,034	5,235	5,444	5,662	5,889	6,124
17	**Non-network opex**	6,732	6,264	7,521	7,972	8,371	8,705	9,054	9,416	9,792	10,184	10,591
18	**Operational expenditure**	12,894	14,433	16,518	17,195	18,181	18,688	19,280	19,817	20,746	21,358	22,487
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												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	3,015	2,615	3,078	3,078	3,078	3,078	3,078	3,078	3,078	3,078	3,078
23	Vegetation management	1,021	1,636	1,643	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653
24	Routine and corrective maintenance and inspection	1,554	3,058	2,909	2,759	2,942	2,759	2,969	2,792	2,889	2,739	2,922
25	Asset replacement and renewal	573	859	855	793	800	808	467	467	467	467	467
26	**Network Opex**	6,162	8,169	8,486	8,283	8,474	8,299	8,168	7,991	8,088	7,938	8,121
27	System operations and network support	2,053	2,264	2,993	2,993	2,993	2,993	2,993	2,993	2,993	2,993	2,993
28	Business support	4,679	4,000	4,102	4,102	4,102	4,102	4,102	4,102	4,102	4,102	4,102
29	**Non-network opex**	6,732	6,264	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095	7,095
30	**Operational expenditure**	12,894	14,432	15,581	15,378	15,569	15,394	15,263	15,086	15,183	15,033	15,216
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	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance											
37	Cybersecurity (Commission only)	469										
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												
40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	0	183	351	484	625	776	929	1,091	1,253	1,433
44	Vegetation management	-	0	100	187	262	336	416	499	584	675	768
45	Routine and corrective maintenance and inspection	-	1	178	312	465	560	749	842	1,026	1,118	1,356
46	Asset replacement and renewal	-	(0)	51	90	126	163	118	141	165	191	217
47	**Network Opex**	-	0	511	940	1,337	1,684	2,058	2,410	2,866	3,237	3,774
48	System operations and network support	-	-	180	370	538	679	826	979	1,138	1,303	1,475
49	Business support	-	-	246	507	738	931	1,132	1,342	1,560	1,786	2,022
50	**Non-network opex**	-	-	426	877	1,276	1,610	1,959	2,321	2,697	3,089	3,496
51	**Operational expenditure**	-	0	937	1,817	2,613	3,294	4,017	4,731	5,564	6,326	7,271
52												
53	**Commentary on options and considerations made in the assessment of forecast expenditure**											
54	*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.*											
55												

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	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
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	0.2%	2.3%	97.4%	–	3	0.1%
11	All	Overhead Line	Wood poles	No.	7.0%	6.4%	15.4%	10.0%	61.2%	–	2	20.0%
12	All	Overhead Line	Other pole types	No.								
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	48.7%	27.0%	24.3%	–	1	0.0%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	48.5%	21.8%	29.7%	–	3	0.0%
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	4.6%	95.4%	–	3	0.0%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km								
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km								
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km								
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km								
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km								
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km								
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km								
23	HV	Subtransmission Cable	Subtransmission submarine cable	km								
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	10.5%	52.6%	31.6%	5.3%	–	3	0.0%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	81.8%	18.2%	–	–	3	0.0%
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.								
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	100.0%	–	3	0.0%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.								
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	100.0%	–	–	–	3	0.0%
30	HV	Zone substation switchgear	33kV RMU	No.								
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.								
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	10.4%	18.8%	56.3%	14.6%	–	3	4.4%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	8.0%	22.0%	–	70.0%	–	3	19.6%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	42.9%	–	57.1%	–	2	0.0%
35												

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)							
36–38	**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.	8.8%	2.9%	2.9%	23.5%	61.8%	–	4	11.1%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.4%	–	61.7%	14.5%	23.4%	–	1	1.3%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km								
42	HV	Distribution Line	SWER conductor	km	–	–	100.0%	–	–	–	1	27.8%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	2.1%	0.8%	10.6%	28.2%	58.3%	–	2	5.0%
44	HV	Distribution Cable	Distribution UG PILC	km	0.5%	–	2.4%	59.1%	38.1%	–	2	0.5%
45	HV	Distribution Cable	Distribution Submarine Cable	km								
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4.5%	6.8%	25.0%	20.5%	43.2%	–	2	23.0%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	0.0%	33.3%	0.0%	13.3%	53.3%	–	2	0.0%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11.8%	18.0%	22.6%	24.7%	22.9%	–	2	7.2%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	2.5%	–	2.5%	2.5%	92.4%	–	3	7.6%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.7%	1.4%	1.4%	1.0%	95.0%	–	3	3.5%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	32.8%	28.2%	21.7%	17.4%	–	2	3.9%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	0.4%	2.5%	3.5%	93.6%	–	3	4.8%
53	HV	Distribution Transformer	Voltage regulators	No.	–	27.3%	36.4%	18.2%	18.2%	–	3	22.0%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.								
55	LV	LV Line	LV OH Conductor	km	0.1%	0.0%	70.3%	6.3%	23.3%	–	1	1.5%
56	LV	LV Cable	LV UG Cable	km	1.7%	10.6%	16.5%	44.9%	26.4%	–	2	1.8%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.0%	5.0%	14.9%	57.1%	23.1%	–	2	0.0%
58	LV	Connections	OH/UG consumer service connections	No.	14.0%	34.2%	28.7%	14.5%	8.5%	–	1	1.0%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	5.6%	26.8%	31.8%	28.5%	7.3%	–	3	22.0%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	10.3%	15.1%	22.1%	37.4%	15.1%	–	2	13.3%
61	All	Capacitor Banks	Capacitors including controls	No.	–	100%	–	–	–	–	3	100.0%
62	All	Load Control	Centralised plant	Lot	–	100%	–	–	–	–	3	50.0%
63	All	Load Control	Relays	No.	11.4%	20.9%	37.6%	26.7%	3.4%	–	1	1.0%
64	All	Civils	Cable Tunnels	km								

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

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**
9	TeAraroa	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint supported by Generation
10	Ruatoria	2	-	N-1 Switched	2	-	-	-	Transformer	Constraint supported by Generation
11	Tokomaru	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint Suported by adjacent Substations
12	Tolaga	1	-	N-1 Switched	2	-	-	-	Transformer	Constraint supported by Generation
13	Kaiti	8	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations
14	Port	8	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations
15	Gisborne	55	60	N-1	60	91%	60	91%	No constraint within +5 years	
16	Carnarvon	15	13	N-1	24	118%	13	118%	No constraint within +5 years	Current Peak caused when load transferred to site during contingency
17	Parkinson	9	13	N-1	24	69%	13	69%	Transformer	Constraint Suported by adjacent Substations
18	Makaraka	8	-	N-1 Switched	7	-	-	-	Transformer	Constraint Suported by adjacent Substations
19	Patutahi	4	-	N-1 Switched	5	-	-	-	Transformer	Constraint Suported by adjacent Substations
20	Pehiri	0	-	N-1 Switched	1	-	-	-	Transformer	Constraint Suported by adjacent Substations
21	Ngatapa	0	-	N-1 Switched	2	-	-	-	Transformer	Constraint Suported by adjacent Substations
22	Puha	2	-	N-1 Switched	2	-	-	-	Transformer	Constraint supported by Generation
23	JNL	2	-	N-1 Switched	5	-	-	-	Transformer	Constraint Suported by adjacent Substations
24	Matawhero	5	13	N-1	18	39%	13	39%	No constraint within +5 years	
25	Tuai	1	5	N	-	13%	5	13%	Transformer	Portable Generation Used for extended repair time
26	Kiwi	5	7	N	-	70%	7	70%	Transformer	Generation Infeed
27	Wairoa	10	10	N-1	13	98%	10	98%	No constraint within +5 years	Constraint supported by Generation
	Blacks pad	2	-	N-1 Switched	2	-	-	-	Transformer	Constraint supported by Generation
	Tahaenui	1	-	N-1 Switched	2	-	-	-	Transformer	Constraint Suported by adjacent Substations
28	Waihi	5	7	N	-	70%	7	70%	Transformer	Generation Infeed

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	Firstlight Network
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

ch ref								
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected during year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10								
11		*Consumer types defined by EDB**						
12		Domestic/Residential	19,962	20,067	20,172	20,278	20,384	20,491
13		Commercial	6,395	6,411	6,427	6,443	6,459	6,475
14		Large Commercial	65	65	65	65	65	65
15		Industrial	5	5	5	5	5	5
16								
17		**Connections total**	26,427	26,548	26,669	26,791	26,913	27,036
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	86	137	94	114	218	223
24		Capacity of distributed generation installed in year (MVA)	14	19	19	20	21	22
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)**						
28		GXP demand	58	60	61	61	61	62
29	*plus*	Distributed generation output at HV and above	7	5	5	5	5	5
30		**Maximum coincident system demand**	65	66	66	66	67	67
31	*less*	Net transfers to (from) other EDBs at HV and above						
32		**Demand on system for supply to consumers' connection points**	65	66	66	66	67	67
33		**Electricity volumes carried (GWh)**						
34		Electricity supplied from GXPs	287	280	280	280	280	281
35	*less*	Electricity exports to GXPs	-	-	-	-	-	-
36	*plus*	Electricity supplied from distributed generation	25	31	31	32	32	32
37	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38		**Electricity entering system for supply to ICPs**	312	311	311	312	312	313
39	*less*	Total energy delivered to ICPs	286	287	287	288	289	289
40		**Losses**	26	24	24	24	24	24
41								
42		**Load factor**	55%	54%	54%	54%	53%	53%
43		**Loss ratio**	8.3%	7.7%	7.7%	7.7%	7.7%	-
44								

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	84.8	101.1	101.1	101.1	101.1	101.1
12	Class C (unplanned interruptions on the network)	170.0	200.0	200.0	200.0	200.0	200.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.50	0.67	0.67	0.67	0.67	0.67
15	Class C (unplanned interruptions on the network)	2.80	2.71	2.71	2.71	2.71	2.71

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Gisborne**

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							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	42.4	50.6	50.6	50.6	50.6	50.6
12	Class C (unplanned interruptions on the network)	85.0	100.0	100.0	100.0	100.0	100.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.25	0.34	0.34	0.34	0.34	0.34
15	Class C (unplanned interruptions on the network)	1.40	1.36	1.36	1.36	1.36	1.36

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Network / Sub-network Name	**Wairoa**

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							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	42.4	50.6	50.6	50.6	50.6	50.6
12	Class C (unplanned interruptions on the network)	85.0	100.0	100.0	100.0	100.0	100.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.25	0.34	0.34	0.34	0.34	0.34
15	Class C (unplanned interruptions on the network)	1.40	1.36	1.36	1.36	1.36	1.36

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**AMMAT and the Risk Segment of ISO 55001**

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	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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?	2.5	Most linkages are in place and evidence is available to demonstrate that, where appropriate, the organization's asset management strategy is consistent with its other organizational policies and strategies. The organization has also identified and considered the requirements of relevant stakeholders	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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?	2.5	The asset management strategy takes account of the lifecycle of most of its assets, asset types and asset systems.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**AMMAT and the Risk Segment of ISO 55001**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2.5	The organisation's arrangements cover most of the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	**Firstlight Network**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**AMMAT and the Risk Segment of ISO 55001**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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	The appointed person or persons have full responsibility for ensuring that the organization's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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?	2.5	An effective process exists for determining the resources needed for asset management and sufficient resources are available, however filling some roles is proving difficult.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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**	The organisation can demonstrate that plan(s) are in place, and are effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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**	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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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 .

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?	2.5	Competency requirements are identified and assessed for most people carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

Company Name	**Firstlight Network**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 .

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	**3**	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	**2.5**	Identification and assessment of asset related risk across the asset lifecycle are mostly documented. The organization can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	**2.5**	Outputs from risk assessments are regularly used as inputs to develop resources, training and competency requirements	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	**2.5**	Evidence exists to demonstrate that the organization's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Some mechanisms are in place for identifying relevant legal and statutory requirements.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2.5	Effective process(es) and procedure(s) are in place to manage and control most of the implementation of the asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	The organization has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non-compliance or incidents identified by investigations, compliance evaluation or audit.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**AMMAT and the Risk Segment of ISO 55001**

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 .

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 organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	AMMAT independent assessment completed August 2023 by Utility Consultants ltd	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.

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AMP Planning Period	**1 April 2023 – 31 March 2033**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
Asset Management Standard Applied	**AMMAT and the Risk Segment of ISO 55001**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Firstlight Network**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Directors Certificate

DIRECTORS' CERTIFICATION

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

ASSET MANAGEMENT PLAN 2023

Clause 2.9.1

We, Fiona Oliver and Jason McDonald, being directors of Firstlight Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a. The following attached information of Firstlight Network Limited prepared for the purpose of clauses 2.6.1, 2.6.3, 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 measured on a basis consistent with regulatory requirements or recognised industry standards.

c. The forecast in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which align with Firstlight Network Limited's corporate vision and strategy and are documented in retained records.

Fiona Oliver	Fiona Oliver
Director Name	Director Signature
Jason McDonald	J McDonald
Director Name	Director Signature

27 September 2023

Date