THEPOWERCOMPANYLTD

Asset Management Plan 2021 - 2031

Publicly disclosed in March 2021

Contents

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Liability Disclaimer

The information and statements made in this AMP are prepared on assumptions, projections and forecasts made by The Power Company Limited (TPCL) and represent The Power Company's intentions and opinions at the date of issue (31 March 2021). Circumstances may change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and The Power Company may, at a later date, decide to take different actions to those that it currently intends to take. The Power Company may also change any information in this document at any time.

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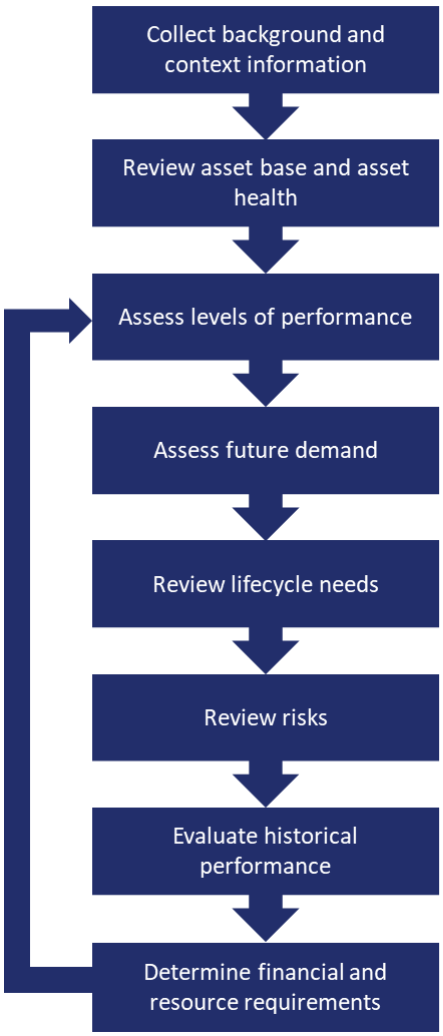
Preparation of the Asset Management Plan

The AMP is produced by PowerNet after extensive consultation throughout the business, with TPCL's Board of Directors, and with TPCL's customers. The AMP is approved by TPCL Board prior to the end of March of each year when it is publically disclosed.

The Asset Management Plan (AMP) development restarts in July every year in order to deliver a new or updated AMP by end March of the following year. The following diagram shows the process followed in the development of the AMP:



- Regulatory Environment
- Environmental Influences
- Purpose, critical success factors, strategic goals
- Financial and economic environment
- Technological developments
  - Service areas
  - Network configuration, resilience, redundancy
  - Assets and asset health details

- Regulatory criteria
- Customer requirements and expectations
- Internal efficiency and effectiveness
- Target levels and measurement
  - Known customer initiatives – supply and demand
  - Regional and local development plans
  - Population growth
  - Social and economic developments and changes
- Condition monitoring
- Asset lifecycle planning and information systems
- Operations and maintenance needs
- Asset replacement and renewal requirements
  - Risk strategy, policy, tolerance levels
  - Risk management methodologies
  - Specific asset related risk
  - Emergency response and contingency
- Historical performance against asset creation plans
- Historical performance against maintenance plans
- Historical performance against service level targets
- Performance against asset management best practice
- Gap analysis and corrective measures
  - Capital and operating expenditure requirements
  - Vehicle and equipment requirements
  - Human resource requirements

We use the finalised and audited information from the immediate past financial year as the base data for the development of the new plan. This is the most accurate data available at that stage of the process. Any forecast figures will still be highly inaccurate.

These figures are the figures used for the asset life cycle planning throughout the document. Where forecast figures are shown, they are indicative and for information only. They will change after the financial year end close and the annual audit.

The world is currently experiencing a pandemic caused by a new strain of coronavirus. Covid-19 is spreading around the world. This is already affecting our supply chain and it may have an effect on the resources available to execute this plan. This AMP assumes that the pandemic will be controlled and that it will not have a significant effect on the availability of skills, equipment and material. Should this not be the case, the plan will be subject to change.

0. Summary

0.1. Background and Objectives

The Power Company Limited (TPCL) is the disclosing entity for the electricity lines businesses that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff), supplying approximately 36,436 customers.

TPCL's Asset Management Plan (AMP) provides an internal asset management framework for TPCL's network. Disclosure in this format is also intended to meet the requirements of Electricity Distribution Information Disclosure Determination as amended on 21 December 2017 for the ten year planning period from 1 April 2021 to 31 March 2031. Other key asset management documents for TPCL are;

- The Annual Works Programme (AWP) detailing the capital and operation expenditure forecasts for the next ten years being produced as part of the development of the AMP.
- The Annual Business Plan (ABP) which consolidates the first three years of the AMP along with any recent strategic, commercial, asset or operational issues from the wider business. The ABP defines the priorities and actions for the year ahead. It also forms the principal accountability mechanism between TPCL's Board and its shareholders.

TPCL's business goals are driven mainly by shareholder's and customers' expectations. Aligned corporate and asset management strategies have been developed to guide TPCL's commercial operation, investment, risk management, business efficiency and customer satisfaction objectives.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust and make the best use of their funds. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance.

Customers, via the electricity retailers, provide TPCL's revenue in return for the services provided by TPCL network assets. It is important for TPCL to meet customers' expectations. Annual customer surveys are undertaken to monitor customer satisfaction with service levels. Targets are set aimed at ensuring standards are maintained or improved. As per ComCom practice, we use the term 'customers' to mean the entities connected to the local lines company, which can be households or businesses. Most customers do not have a direct relationship with their local lines company. Rather, they will engage with an electricity retailer to which they pay their bill (see for example the ComCom publication "Trends in local lines company performance" published in December 2020, p2)

Stakeholders' interests are accommodated as far as possible; any conflicting interests are managed by using a priority hierarchy considering safety, viability, pricing, supply quality, and compliance, in that order.

0.2. Assets Covered

TPCL owns and operates an electrically contiguous network which is supplied by four Grid Exit Points (GXPs) at Invercargill, North Makarewa, Gore, and Edendale; and up to 72MW of injected generation from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited Partnership's Flat Hill wind farm. In total, TPCL supplies 36,436 residential, commercial, and industrial customers across all network areas.

Key industries within TPCL's network area include sheep, beef and dairy farming, meat processing, black and brown coal mining, forestry, timber processing, and tourism.

TPCL owns and operates 37 zone substations. The distribution network is predominantly overhead which is mainly meshed between substations with reasonable backup capability. Most distribution off this main distribution is radial, with only some meshing.

0.3. Service Levels

TPCL sets and maintains a number of service levels on behalf of its stakeholders, especially its customers. Two important metrics measuring network reliability are SAIFI and SAIDI:

- SAIFI is a measure of outage frequency which translates to the number of interruptions that the average customer can expect annually. TPCL is forecasting a SAIFI of about 4.03 for the 21/22 year.
- SAIDI is a measure of outage duration which translates to the number of minutes that the average customer can expect to be without power per annum. TPCL is forecasting SAIDI of about 284.94 minutes for the 2021/22 year.
- These forecasts are set from the base performance of the 2020/21 financial year. Forecasts are for reliability to remain relatively stable for the following four years as the effects of the ageing network are balanced against capital expenditure to keep network performance at a non material deterioration level. The current CAPEX allocation for the outer years from 2025/26 onwards have an increased focus on asset replacement and renewals. Increased activity will influence planned outage performance while unplanned outages will reduce as a result of asset condition improvement. Short term values variation can be expected due to the low number of faults creating statistical volatility and severe weather events. The rollout to automate network tie points are to continue under the ABS replacement program.
- Secondary service levels are also set for customer satisfaction for those customers who have experienced an outage (both planned and unplanned). This measures their satisfaction with the length of time they were without supply, and with the information made available to them about their outages. Independent surveys are undertaken annually to determine how customers perceive the service levels they receive from TPCL; generally responses are very positive.

Other service levels maintained are the compliance with safety legislation, amenity value legislation, and regulations requiring certain performance standards for the business, while avoiding interference with other parties.

In addition, TPCL is required to set financial efficiency and energy efficiency service levels. For financial efficiency, TPCL has adopted a set of six metrics from the current Information Disclosure format, and aims to maintain or improve them from current levels. For efficiency of energy delivery TPCL is aiming to achieve an overall load factor of 65%, capacity utilisation of 30%, and loss ratio of 7.0%.

Benchmarking service levels against other electricity distribution businesses indicates TPCL is performing well on behalf of its stakeholders.

0.4. Development

Development may be driven either by the need to create additional network capacity for supplying increasing demand, or by the need to maintain or improve service levels. These drivers are monitored and trigger points set to identify when development projects are needed. When a development trigger is reached, several options are considered with the most cost efficient option selected as a solution. Standardisation is a valuable strategy in providing cost efficiencies in the delivery of capital projects.

Forecasts of demand growth are required to help TPCL predict when in future years the development triggers will be reached, thus enabling effective planning of future projects. Historical demand is trended and projected into future years while accounting for foreseeable future drivers that may cause a change to the current trend. Projections and associated planning are based on what is considered the most likely scenario, while TPCL's strategy of deferring capital expenditure until necessary, minimises the risk of overinvestment.

TPCL's work programme includes the following capital expenditure on network development for 2021/22:

- Consumer Connections – the provision of a connection point and additional network capacity as needed for new customers is budgeted at $2,62M.
- System Growth –Continuation of the Lumsden / Riversdale 22kV Line upgrade and finalisation of the first phase in the upgrade of the Athol 5, 11kV feeder upgrade combined at $2,31M.
- Asset Relocations – a budget for the relocation of miscellaneous poles or other assets as requested by other parties. $0,12M.
- Quality of Supply – Supply Quality Upgrades, Site made ready projects for the use of the Mobile Substation and Network Improvement Projects. $0,47M.
- Other Reliability, Safety and Environmental – This includes Earth mat upgrades, Retrofit of arc-flash protection on indoor 11kV switchboards, Remote Area Power Supplies, Hillside protection upgrade and communication network upgrades. $4,17M.

Total capital expenditure budget, including Asset Replacement and Renewal, as described under "Lifecycle" below) is $22,12M for 2021/22, with budgets for the following two years set at $21,13M and $21,42M respectively.

Table 1: Material Development Projects

Project	Driver	Year	$000
Riversdale Substation Upgrade	System Growth	2023/24-2024/25	3,114
Kelso Transformer Upgrade	System Growth	2025/26	141
Glenham Transformer Upgrade	System Growth	2025/26	1,411
Lumsden / Riversdale 22kV Line Upgrades	System Growth	2021/22-2024/25	2,657
22kV Upgrade Athol - Kingston	System Growth	2021/22-2024/25	6,914
Earth Upgrades	Safety	2021/25-2030/31	11,638 then 1,210 from 25/26 ongoing
Substation Safety	Safety	2021/22-2022/23	244 pa
Remote Area power Supply	Other	2021/24 – 2027/31	133p.a. & 1,163 for period
Hillside Protection Remediation	Safety	2021/22	369
Communications Projects	Other	2021/22-2029/31	2,725

0.5. Lifecycle

Once an asset has been installed it must be managed throughout its lifecycle to continue to fulfil its purpose for as long as required and to minimise any adverse effects the asset might create. Maintenance activities are generally undertaken throughout an asset's operational life to support its continued reliable service. At some point the asset will reach its end of life and will be retired from service. At that point the asset will be replaced (assuming the need remains) while the retired asset must be disposed of appropriately.

TPCL's work program includes the following capital expenditure on asset lifecycle management:

- Asset Replacement and Renewal – replacement of assets that are at the end of their economic life, or in some cases major refurbishment of assets to extend their expected life. The 2021/22 budget is $12,502M dominated heavily by 11kV Line Replacement ($5,334M), ABS Renewals ($1,548M) and Power Transformer Refurbishment ($0,912M). The budgets for the following two years are set at $11,606M and $11,449M respectively.

The remainder of TPCL's works program is made up of the following operational expenditure on asset lifecycle management:

- Asset Replacement and Renewal – minor refurbishment work that doesn't impact on an asset's valuation is budgeted at $0,880M per annum ongoing.
- Vegetation Management – a budget allocation of $1,215M annually has been allocated for the trimming of trees to prevent contact with overhead lines.

- Routine and Corrective Maintenance and Inspection – inspection, testing and investigation of network condition and resulting maintenance or repair as well as general routine asset maintenance and repairs budgeted at $4,910M in 2021/22, $ 4,916M in 2022/23 with further averaged allocations of $4,534M annually.
- Service Interruptions and Emergencies – reactive work following network faults and customer outages to locate, isolate and repair faulty network assets budgeted at $3,374M each year ongoing until 2025/26 followed by $3,532M onwards.

Total network operational expenditure is budgeted at $10,380M for 2021/22, $10,365 in 2022/23 with a slight reduction to $9,983M for 2023/24.

A non network Capex allocation of $65k have been included for the upgrade of buildings at Racecourse Road for the 2021/22 financial year.

Table 2: Material Non-Routine Lifecycle Projects

Project	Driver	Year	$000
ABS renewals	Renewal	2021/22-2029/30	11,801
Orawia Substation Upgrade	Replacement	2022/23-2023/24	1,304
Makarewa Switchboard Replacement	Renewal	2024/25-2025/26	2,029
Bluff Switchboard Replacement	Renewal	2024/25-2025/26	1,549
Gore Ripple Plant Upgrade	Replacement	2021/22	154
Seaward Bush RTU, Arc Flash & Structure Replacement	Replacement	2021/22	598
Gore LV link box renewals	Replacement	2021/22	110
33kV Oil Circuit Breaker replacement	Replacement	2021/2-2028/289	3,538

0.6. Risk Management

TPCL is exposed to a wide range of risks, and utilises risk management techniques to reduce risk to acceptable levels. Risks associated with TPCL's network are actively identified through regular reviews. Identified risks are then quantified in terms of the probability that an adverse occurrence will eventuate, consequences for TPCL if it does. We then use a risk matrix to systematically combine the probability and consequence into a resulting level of risk. Risk management looks at the most appropriate options for reducing risk to acceptable levels using the following general methods:

- Terminate – not proceeding with risky activity or eliminating a risk by choosing an alternative approach
- Treat – reduce probability and/or consequence of an adverse occurrence
- Transfer – engage a more suitable party to effectively manage a certain risk
- Tolerate – accept a low level risk as tolerable (including residual risk after treatment of higher level risks)

TPCL's risk management framework recognises that resources for managing risk are finite. It may be appropriate to increase certain resources to manage risk appropriately. Ultimately, however, risk treatment measures identified need to be prioritised using a philosophy of greatest risk reduction for the resources available. Many risks have been identified and are being managed under the following broad categories:

- Assets
- People
- Community/Stakeholders
- Ownership/Governance
- Legal & Regulatory
- Economic/Political

For potential serious business interruptions, TPCL has developed a Business Continuity Plan and has a Pandemic Action Plan for use in the outbreak of any highly infectious illness. TPCL also holds critical network spares and has contingency operating plans to support efficient restoration of supply following unexpected equipment failure. It also holds a range of business insurances.

0.7. Performance

For the financial year ending 31st March 2020 TPCL's finalised and audited performance is summarised as follows:

Capital expenditure on assets was 5% over target mainly due to the new large consumer connections. Operational expenditure was 12% under target due to reduced expenditure in maintenance and asset renewals.

Reliability performance on the overall network was below par. Exceeding the target with SAIFI at 3.50 above the target of 2.84 and SAIDI at 255.7 above the target of 149.62.

Network efficiency performance was satisfactory with the target of less than 7.0% for Loss Ratio achieved. The Capacity Utilisation and Load Factor targets were not achieved, however the results were very close to target.

Financial efficiency targets were partially achieved for Non-Network Operational Expenditure but not achieved for Network Operational Expenditure.

0.8. Capability to Deliver

PowerNet owns the many systems, processes, and tools used to effectively and efficiently manage TPCL's network assets. PowerNet's information systems hold data about TPCL's network assets including technical details, location, operational states, and condition. This data is collated and displayed in various ways to help support efficient decision making for TPCL's asset management planning and activities.

TPCL's business is funded from the revenue received from customers via several electricity retailers and in return TPCL maintains a network for the conveyance of electricity to these customers within certain service levels. Significant expenditure is required each year to maintain network assets and to develop the network to meet increasing customer demand.

Staffing and contracting resources is an ongoing issue that TPCL is managing, and TPCL's Annual Works Program recognises existing and future resourcing levels as constraints to be managed over time. TPCL will rely on internal field services to carry out much of the operational, maintenance, and development work on its network, but it will also utilise local contractors where additional resources are required.

TPCL's revised revenue is lower than preceding periods to align with the Commerce Commission's intent to pass through savings on the cost of capital deployed to customers. This imposes significant constraints on TPCL's ability to meet the network's renewal needs and our target is to have no material deteriation of the network performance.

1. Background and Objectives

Infrastructure, in the form of public buildings, roads, water and sewerage systems, electricity and other services, supports quality of life and is the foundation of a healthy economy. Apart from its social benefits, electricity is also a driving factor in the economy. Its usage ranges from communication and transportation to production.

The Power Company Limited (TPCL) is the electricity lines business that conveys electricity throughout the wider Southland area (except for the majority of Invercargill and Bluff) to approximately 36436 customer connections on behalf of eighteen energy retailers (per participant code utilised). The wider TPCL entity also includes the following associations:

- A 50% stake in PowerNet, an electricity lines management company jointly owned with Electricity Invercargill Limited (EIL). This is an unregulated entity and is therefore not subject to any disclosure requirements.
- A 75.1% stake in Electricity Southland Limited (ESL), which distributes electricity in the Frankton and Wanaka areas of Central Otago. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of TPCL, EIL and ESL.
- A 75.1% stake in OtagoNet. The entity for disclosure is OtagoNet Joint Venture (OJV), and its AMP is prepared and disclosed by PowerNet which manages the OJV assets along with those of TPCL, EIL and ESL.
- A 25% stake in Southern Generation Limited Partnership, a generation company with wind and hydro assets in New Zealand jointly owned with EIL and Pioneer Generation Ltd.

The interrelationship of these entities with the various holding companies and shareholders, along with the accounting treatment of results, is described in TPCL's annual report.

1.1. Purpose Statement

The purpose of TPCL's Asset Management Plan (AMP) is to provide an internal governance and management framework for asset management practice on TPCL's network. Disclosure in this format is also intended to assist in meeting the requirements of Section 2.6, Attachment A and Schedules 11, 12, and 13 of the Electricity Distribution Information Disclosure Determination 2012 as amended.

The plan:

- documents the nature, extent, age, utilisation, condition, performance and value of the infrastructure;
- identifies existing and proposed levels of service to be achieved over a five year period, as well as any expected changes in demand;
- identifies the life-cycle management needs (development, renewal, operations and maintenance and any disposal) over the five year period;
- assesses capital and operational budget needs and funding implications; and
- assesses the prevailing infrastructure asset management practice and identifies further improvements.

1.2. Commerce Commission Determination – November 2019

Part 4 of the Commerce Act 1986 (the Act) requires the Commerce Commission to reset the current DPP for distributors that are subject to price-quality regulation four months before the end of the current DPP period. As from 1 April 2020, distributors are being subjected to new requirements set out in the DPP determination.

The determination does not directly affect TPC, as it is an unregulated network. We do however subscribe to the intent expressed by the Commerce Commission, namely to provide sufficient flexibility to accommodate increasing uncertainty and change across the distribution sector. Quality of service incentives is a major focus of the determination. The approach followed is one of 'no material deterioration'. The stated intent is that aligning reliability incentives to the value consumers place on reliability frees distributors (within certain bounds) to target the level of reliability and of price that best meets the expectations of their consumers

1.3. Asset Management Objectives

Asset Management refers to a formal approach through which an organisation manages its physical assets and their associated performance, risks and expenditures over their lifecycle for the purpose of achieving the company's vision and business objectives.

The objective of asset management for The Power Company is therefore to ensure that the utility's assets deliver the required function and level of performance, in a sustainable manner at an optimum whole-life cost without comprising health, safety, environmental performance or the organisation's reputation. It therefore contributes directly to the business capability and performance while enhancing customer satisfaction and improving health, safety and environmental performance.

We align our asset management activities with our corporate business plan and targets to ensure that the management of the physical assets enables the delivery of customer and stakeholder value.

We achieve this through the operation of a co-ordinated end-to-end asset management system that:

- Produces an asset management strategy, asset management objectives, and asset performance, asset health and asset condition targets that are consistent with our business priorities and strategic business plan
- Gives consideration to the complete lifecycle of our assets and develops asset management plans that are sustainable, efficient and based upon an optimised consideration of cost, risk and performance
- Promotes interaction with customers and stakeholders to determine their required levels of service
- Optimises and prioritises maintenance and investment activities
- Uses new technologies to appropriately improve efficiency, effectiveness and service levels
- Is supported by asset and financial information, and technical knowledge
- Ensures delivery of the objectives and targets required by our plans
- Ensures that all our activities meet with applicable legislation, statutory and regulatory requirements and integrate with and complements the risk, health & safety, environmental and quality management system requirements of PowerNet; and

- Incorporates regular formal reviews designed to seek and implement continual improvement
- Provides our staff and contractors with sufficient information, training and resources to ensure that we achieve our objectives.

At a more detailed level, this implies that TPCL needs to:

- Set service levels for the electricity distribution services supplied by TPCL, which will meet customer, community and regulatory requirements.
- Understand the network capacity, reliability and security of supply that will be required both now and in the future and the issues that drive these requirements.
- Have an ever-increasing knowledge of TPCL's asset locations, ages, conditions, and likely future behaviour as age increases and operational demands change.
- Have robust and transparent processes in place for managing all phases of the network life cycle from design, procurement, and installation to maintenance, operations and disposal.
- Have adequate provision for funding all phases of the network lifecycle.
- Have adequately considered the classes of risk TPCL's network business faces and ensured that there are systematic processes in place to manage identified risks.
- Make business decisions within systematic and structured frameworks.

This AMP is not intended to be a detailed description of TPCL's assets (these lie in other parts of the business), but rather a description of the thinking, the policies, the strategies, the plans and the resources that TPCL uses and will use to manage the assets.

1.4. AMP Planning Period and Director Approval

TPCL's Asset Management Plan (AMP) is prepared annually by PowerNet however an "AMP update" is produced in place of a full AMP up to three years within each five year default price path period as allowed for by the Electricity Distribution Information Disclosure Determination 2012 (latest amendments incorporated). The AMP update which focusses on updates to the development and lifecycle works and expenditure is a cut down version of the full AMP represented by this document.

This latest edition was prepared during April 2020 to March 2021 and covers the ten year period from 1 April 2021 to 31 March 2031. It was approved by TPCL's Board on 24 March 2021 (see Appendix Directors Approval) and publicly disclosed at the end of March 2021.

There is a degree of uncertainty in any predictions of the future with the immediate future reasonably predictable and the longer term becoming increasingly uncertain.

The first year of the AMP is considered reasonably certain. Planned capital works are generally well planned and only subject to minor variations. New customer connections are driven by turbulent commodity markets, public policy trends and possible generation opportunities so while trends are reasonably predictable, year to year variation around those trends can still be significant, especially with larger capacity connections that tend to have lower and more sporadic connection rates but have larger individual impact.

Planned maintenance works are relatively predictable as most tasks require a similar amount of effort year to year. Occasionally step changes are warranted due to age profiles or if new initiatives are introduced, but these changes are planned in advance. Reactive maintenance requirements are less predictable. Response to service interruptions is probabilistic by nature and can vary substantially each

year. Network faults on overhead parts of the network are also unpredictable, being heavily influenced by the weather.

The two to four year timeframe has lower certainty. However customer connection rates, maintenance and response to service interruptions are expected to continue the current trend to a reasonable degree. Major projects are typically identified and scheduled however as detailed scope, design and costings are developed alternative options may be progressed influencing expenditure and timing. External influences tend to cause more minor projects to be considered within this timeframe each year especially the changing perceptions around health and safety.

The final five year period of the AMP's ten year planning horizon has little certainty if any. Projects for age based replacements can be proposed and growth trends can be used to predict when capacity triggers will be reached. However standards may change and new maintenance philosophies may be developed (and continual improvement in asset management practice means this is likely) potentially having a large impact on scope and timeframes for these projects. Experience shows these changes and other external influences are likely to introduce and reshape major and minor projects within this time frame but are very difficult to predict.

1.5. Drivers and Constraints

TPCL's business goals are driven by its stakeholder's interests, mainly the shareholder's and customer's expectations. Also shaping business operation is the wider context in which the business operates which includes a number of drivers. These drivers range from governmental and regulatory strategies that may create incentives or impose constraints, to absolute issues such as the unpredictability of weather or the laws of physics.

This section describes the identification of TPCL's stakeholders, their interests in TPCL, how these interests are met and how conflicts between stakeholder's expectations are managed before identifying other influences that drive and shape TPCL's business.

Stakeholder Interests

The stakeholders TPCL has identified are listed in the following tables with the stakeholder's interests and how these interests are identified shown in Table 3 and Table 4 respectively.

Table 5 then shows how stakeholder's interests are accommodated in TPCL's asset management practices. A stakeholder is identified as any person or organisation that does or may do any of the following:

- Have a financial interest in TPCL (be it equity or debt).
- Pay money to TPCL (either directly or through an intermediary) for delivering service.
- Is physically connected to TPCL's network.
- Use TPCL's network for conveying electricity.
- Supply TPCL with goods or services (includes labour).
- Is affected by the existence, nature or condition of the network (especially if it is in an unsafe condition).
- Has a statutory obligation to perform an activity in relation to TPCL network's existence or operation (such as request disclosure data, regulate prices, investigate accidents or District

Table 3: Key stakeholder interests

Interests:	Viability	Price	Quality	Safety	Compliance
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	✓	✓	✓	✓	✓
Connected Customers	✓	✓	✓	✓	
Contracted Manager (PowerNet)	✓	✓	✓	✓	✓
Ministry of Business, Innovation & Employment		✓	✓	✓	✓
Commerce Commission	✓	✓	✓		✓
Electricity Authority					✓
Electricity & Gas Complaints Commission			✓		✓
Councils (as regulators)				✓	✓
Transport Agency				✓	✓
Worksafe				✓	✓
Industry Representative Groups	✓	✓	✓		
Public (as distinct from customers)				✓	✓
Mass-market Representative Groups	✓	✓	✓		
Staff and Contractors	✓			✓	✓
Energy Retailers	✓	✓	✓		
Transpower		✓	✓	✓	
Suppliers of Goods and Services	✓				
Land owners				✓	✓
Bankers	✓	✓		✓	✓

Table 4: Identifying stakeholder's interests

Stakeholder	How Interests are Identified
Southland Electric Power Supply (SEPS) Consumer Trust (Shareholder)	• By their approval or required amendment of the SOI • Regular meetings between the directors and executive
Connected Customers	• Regular discussions with large industrial customers as part of their on-going development needs • Customer consultation evenings (meetings open to public) • Annual customer surveys
Contracted Manager (PowerNet)	• Board Chairman weekly meeting with the Chief Executive • Board meets monthly with Chief Executive and PowerNet Staff
Ministry of Business, Innovation & Employment	• Release of legislation, regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Commerce Commission	• Regular bulletins on various matters • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity Authority	• Weekly updates and briefing sessions • Release of regulations and discussion papers • Analysis of submissions on discussion papers • Conferences following submission process • General information on their website
Electricity & Gas Complaints Commission	• Reviewing their decisions in regard to other lines companies
Councils (as regulators)	• Formally as necessary to discuss issues such as assets on Council land

Stakeholder	How Interests are Identified
	• Formally as District Plans are reviewed
Transport Agency	• Formally as required
Worksafe	• Promulgated regulations and codes of practice • Audits of TPCL's activities • Audit reports from other lines businesses
Industry Representative Groups	• Informal contact with group representatives
Public (as distinct from customers)	• Word of mouth • Feedback from public meetings
Mass-market Representative Groups	• Informal contact with group representatives
Staff & Contractors	• Regular staff briefings • Regular contractor meetings
Energy Retailers	• Annual consultation with retailers
Transpower	• Deliver transmission grid energy into TPCL network • Regular engagement on network performance and asset integration • Annual input on future demand forecasts • Planned and unplanned network outage co-ordination • Through costs are paid by TPCL to Transpower
Suppliers of Goods & Services	• Regular supply meetings • Newsletters
Land Owners	• Individual discussions as required
Bankers	• Regular meetings between bankers, PowerNet's CE & CFO • By adhering to TPCL's treasury/borrowing policy • By adhering to banking covenants

Table 5: Accommodating Stakeholder's Interests

Interest	Description	How TPCL Accommodates Interests
Viability	Viability is necessary to ensure that the shareholder and other providers of finance such as bankers have sufficient reason to keep investing in TPCL.	Stakeholder's needs for long-term viability are accommodated by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital. In general terms this will need to be at least as good as the stakeholders could obtain from a term deposit at the bank plus a margin to reflect the ever-increasing risks to the capital in the business. Earnings are set by estimating the level of expenditure that will maintain Service Levels within targets and the revenue set to provide the required returns.
Price	Price is a key means of both gathering revenue and signalling underlying costs. Getting prices wrong could result in levels of supply reliability that are less than or greater than what TPCL's customers want.	TPCL's total revenue is constrained by the price path threshold regime. Prices will be restrained to within the limits prescribed by the price path threshold, unless doing so would comprise safety or viability Failure to gather sufficient revenue to fund reliable assets will interfere with customer's business activities, and conversely gathering too much revenue will result in an unjustified transfer of wealth from customers to shareholders.

Interest	Description	How TPCL Accommodates Interests
		TPCL's pricing methodology is expected to be cost-reflective, but issues such as the Low Fixed Charges requirements can distort this.
Supply Quality	Emphasis on continuity, restoration of supply and reducing flicker is essential to minimising interruptions to customers' businesses.	Stakeholder's needs for supply quality will be accommodated by focusing resources on continuity and restoration of supply. The most recent mass-market survey indicated a general satisfaction with the present supply quality.
Safety	Staff, contractors and the public at large must be able to move around and work on the network in total safety.	The public at large are kept safe by ensuring that all above-ground assets are structurally sound, live conductors are well out of reach, all enclosures are kept locked and all exposed metal within touching distance of the ground is earthed. The safety of staff and contractors is ensured by providing all necessary equipment, improving safe work practices and ensuring that they are stood down in unsafe conditions. Motorists will be kept safe by ensuring that above-ground structures are kept as far as possible from the carriage way within the constraints faced in regard to private land and road reserve.
Compliance	Compliance is necessary with many statutory requirements ranging from safety to disclosing information.	All safety issues will be adequately documented and available for inspection by authorised agencies. Performance information will be disclosed in a timely and compliant fashion.

TPCL's commercial goal is to achieve commercial efficiency on behalf of their shareholder Southland Electric Power Supply (SEPS) Consumer Trust. This creates a primary driver for TPCL and formal accountabilities to the shareholder are in place for financial and network performance. See section Key Planning Documents (Statement of Intent).

Customers, via the electricity retailers, provide TPCL's revenue in return for the services provided by TPCL network assets. Due to the importance TPCL places on meeting customers' expectations annual customer surveys are undertaken to monitor customer satisfaction with service level targets aimed at ensuring standards are maintained or improved. See sections Service Levels and Performance for details of these surveys, customer feedback and performance targets TPCL sets.

TPCL is subject to the requirement to compile and publically disclose performance and planning information (including the requirement to publish an AMP) and TPCL although not subject to price and quality regulations aims to maintain prices and network reliability in a manner similar to a regulated network. These requirements are established under Part 4 of the Commerce Act 1986.

TPCL is also subject to regulatory restrictions on generating and retailing energy established under the Electricity Industry Act 2010 and requirements for the connection of distributed generation established under the Electricity Industry Participation Code. There is an increasing requirement on Electricity lines businesses to give effect to many aspects of government policy.

Managing Conflicting Stakeholder Interests

TPCL must resolve any identified conflicts around stakeholder interests. To achieve this, the following priority hierarchy is used to analyse the conflicting issues and options available:

1. **Safety**. Top priority is given to safety. The safety of staff, contractors and the public is of paramount importance and is given an exceptionally heavy weighting in asset management decisions.
2. **Viability**. Second priority is viability (as defined above), because without it TPCL will cease to exist which makes supply quality and compliance pointless.
3. **Pricing**. TPCL will give third priority to pricing as a follow on from viability (noting that pricing is only one aspect of viability). TPCL recognises the need to adequately fund its business to ensure that customers' businesses can operate successfully, whilst ensuring that there is not an unjustified transfer of wealth from its customers to its shareholders.
4. **Supply quality**. Supply quality is the fourth priority. Good supply quality makes customers, and therefore TPCL, successful.
5. **Compliance**. A lower priority is given to compliance that is not safety and supply quality related.

Once an appropriate resolution has been determined a recommendation will be presented to management or escalated to the Board for decision.

Other Influences

Other issues TPCL need to understand and around which strategies can be developed are as follows, these issues are not directly related to stakeholders but have a significant impact on TPCL's asset management practice.

- Competitive pressures from other lines companies which might try to supply TPCL customers.
- Pressure from substitute energy sources at end-user level (such as substituting electricity with coal or oil at a facility level) or by offsetting load with distributed generation.
- Advancing technologies such as solar generation coupled with battery storage, which could strand conventional wire utilities.
- Local, national and global economic cycles which effect growth and development.
- Changes to the Southland climate that include more storms and hotter, drier summers.
- Interest rates which can influence the rate at which new customers connect to the network.
- Ensuring sufficient funds and skilled people are available long term to resource TPCL's service requirements.
- Technical regulations including such matters as limiting harmonics to specified levels.
- Safety requirements such as earthing of exposed metal and line clearances.
- Asset configuration, condition and deterioration. These parameters will significantly limit the rate at which TPCL can re-align their large and complex asset base to fit ever-changing strategic goals.
- The laws of physics which govern such fundamental issues as power flows, losses, insulation failure and faults.
- Physical risk exposures. Exposure to events such as flooding, wind, snow, earthquakes and vehicle impacts are generally independent of the strategic context. Issues in which TPCL's risk exposure might depend on the strategic context could be in regard to natural issues such as climate change (increasing severity and frequency of storms) or regulatory issues (say if the transport agency required all poles to be moved back from the carriage way).

1.6. Strategy and Delivery

TPCL's vision, corporate strategies and asset management strategies have been designed to accommodate the interests and expectations of the various stakeholders while recognising the need to work within constraints imposed by stakeholders and the wider issues that affect asset management. Managing conflicts between stakeholders and managing numerous risks to the business are also recognised.

Vision Statement

To be recognised as the leading consumer trust owned electricity sector company and an excellent corporate citizen.

Corporate Strategy

Key corporate drivers from TPCL's Strategic Plan are:

- Manage operations in a progressive and commercial manner
- Undertake new investments which are 'core business', acceptable return for risk involved, and maximise commercial value
- Provide its customers with above average levels of service
- Understand and effectively manage appreciable business risk
- Strive to be an efficient but effective operation
- Pursue alternative technologies and energy forms within the current regulatory requirements

Asset Management Strategy

TPCL's asset management strategy follows these guiding principles:

- Safety by design using the ALARP (as low as reasonable practicable) risk principle
- Minimise long term service delivery cost through condition monitoring and refurbishment
- Replace assets at their (risk considered) economic end of life
- Facilitate network growth through timely implementation of customer driven projects
- Maintain supply quality and security with network upgrades to support forecast growth
- Set performance targets for continuous improvement
- Mitigate against potential effects of natural hazards; seismic, tidal, extreme weather
- Utilise overall cost benefit at all investment levels including the "do nothing" option
- Standardise and optimally resource to provide proficient and efficient service delivery
- Follow new technology trends and judiciously apply to improve service levels
- Undertake initiatives to increase existing asset life or capacity
- Consider alternatives to status quo solutions
- Improve efficiency of electricity distribution for the net benefit of the customer
- Achieve 100% regulatory compliance
- Minimise environmental harm

Interaction of Goals/Strategies

TPCL's vision underpins both Corporate and Asset Management Strategies with linkage between these strategies shown in Table 6.

Table 6: Corporate and Asset Management Strategy Linkage

Corporate Strategies					
Provide its customers with above average levels of service.					
Undertake new investments which are 'core business', acceptable return for risk involved and maximise commercial value.					
Understand and effectively manage appreciable business risk.					
Manage operations in a progressive and commercial manner.					
Strive to be an efficient and effective operation.					
Asset Management Strategies					
Safety by design using the ALARP (as low as reasonably practicable) risk principle		✓	✓		✓
Minimise long term service delivery cost through condition monitoring and refurbishment	✓	✓			✓
Replace assets at their (risk considered) economic end of life	✓	✓	✓		✓
Facilitate network growth through timely implementation of customer driven projects		✓		✓	✓
Maintain supply quality and security with network upgrades to support forecast growth		✓	✓	✓	✓
Set performance targets for continuous improvement		✓			✓
Mitigate against potential effects of natural hazards; seismic, tidal, extreme weather			✓		✓
Utilise overall cost benefit at all investment levels including the "do nothing" option	✓	✓		✓	
Standardise and optimally resource to provide proficient and efficient service delivery	✓	✓			
Follow new technology trends and judiciously apply to improve service levels		✓			✓
Undertake initiatives to increase existing asset life or capacity	✓	✓			
Consider alternatives to status quo solutions	✓	✓			
Improve efficiency of electricity distribution for the net benefit of the customer	✓				✓
Achieve 100% regulatory compliance		✓	✓		✓
Minimise environmental harm		✓	✓		✓

1.7. Key Planning Documents

In addition to the AMP the following documents are produced annually by PowerNet on TPCL's behalf and approved by TPCL as part of the company's planning processes.

Annual Works Programme

The Annual Works Programme (AWP) is produced as part of the AMP development process and is included in the AMP's development and lifecycle planning sections. It covers the same ten year planning horizon as the AMP and lists the works to be undertaken for each financial year.

The AWP details the scope for each activity or project identified, sets the associated budget for the first year and forecasts expenditure for future years. Critical activities are to firstly ensure that this annual works program accurately reflects the projects in the AMP and secondly to ensure that each project is implemented according to the scope prescribed in the works program. Ensuring the AWP is

achievable requires careful consideration of the available workforce and management capabilities as discussed further in Capability To Deliver.

Annual Business Plan

Each year, the first three years of the AMP is consolidated with any recent strategic, commercial, asset or operational issues into TPCL's Annual Business Plan (ABP). The AWP for the year ahead is an important component of the ABP.

The ABP defines the priorities and actions for the year ahead which will contribute to TPCL's long-term alignment with their vision, objectives and strategies, while fully understanding that this alignment process must at times cater for "moving goal posts". The ABP contains the following:

- Core Business, Vision Statement and Critical Success Factors
- Commercial Objectives, The Nature and Scope of Commercial Activity and Company Polices
- Annual Works Programme (first three years)
- Business Plan Financials and Business Unit Reports

Progress updates are reported monthly to assist in monitoring of performance and delivery to plan.

Statement of Intent

TPCL's Statement of Intent (SOI) is a requirement under the constitution of the company, and forms the principal accountability mechanism between TPCL's board and the shareholder; Southland Electric Power Supply Consumer Trust. TPCL's corporate strategies gain shareholder approval via the SOI.

The SOI includes financial performance projections for:

- EBIT% (Percentage Group Earnings Before Tax and Interest on Assets Employed),
- NPAT% (Percentage Group Tax Paid Profit on Equity) and
- Percentage of Consolidated Equity to Total Assets

It also includes the quality performance projections for SAIFI and SAIDI which are set in the AMP Proposed Service Levels.

These projections are given over a three year period, form the heart of the asset management activity and implicitly recognise the inherent trade-off between price and supply quality. The SOI is available at http://www.powernet.co.nz in the Line Owners area under Company Information.

1.8. Interaction between Objectives, Drivers, Strategies and Key Documents

The interaction between TPCL's corporate vision, asset management objectives, business drivers, strategies and key planning documents is shown in Figure 1 and is summarised as follows.

The vision leads to the objectives for TPCL's asset management processes. These asset management processes are documented in the AMP which serves as a guidance and communication mechanism ensuring understanding and consistency within TPCL's asset management company PowerNet and TPCL Board.

The asset management strategies are designed to provide guidance in achieving the asset management objectives while aligning with TPCL's vision and corporate strategies. Stakeholder interests and expectations as well as other external influences create business drivers which shape the strategies. They also shape the asset management objectives and even the corporate vision, however

these tend to remain relatively consistent whereas strategies tend to be more flexible and evolve as the driving factors change with time.

The asset management strategies are applied to the existing network assets to meet the asset management objectives including realising development opportunities as they arise. This involves the setting of performance targets which leads the AWP development.

The AMP incorporating (and especially) the AWP, which is prepared in a format assisting communication of key deliverables, sets and drives asset management works and expenditure to reshape network assets. Delivery of the AWP projects over time creates a network closely aligned with the asset management strategies, objectives and ultimately TPCL's corporate vision while meeting stakeholder expectations, especially the shareholder and network customers.

Capital expenditure budgets and performance targets from the AMP and the AWP are incorporated into the ABP together with any wider business issues providing the overall business planning summary used by the wider management team and TPCL Board. The SOI incorporates performance targets from the AWP including key asset management targets forming the accountability mechanism between TPCL board and the shareholder.

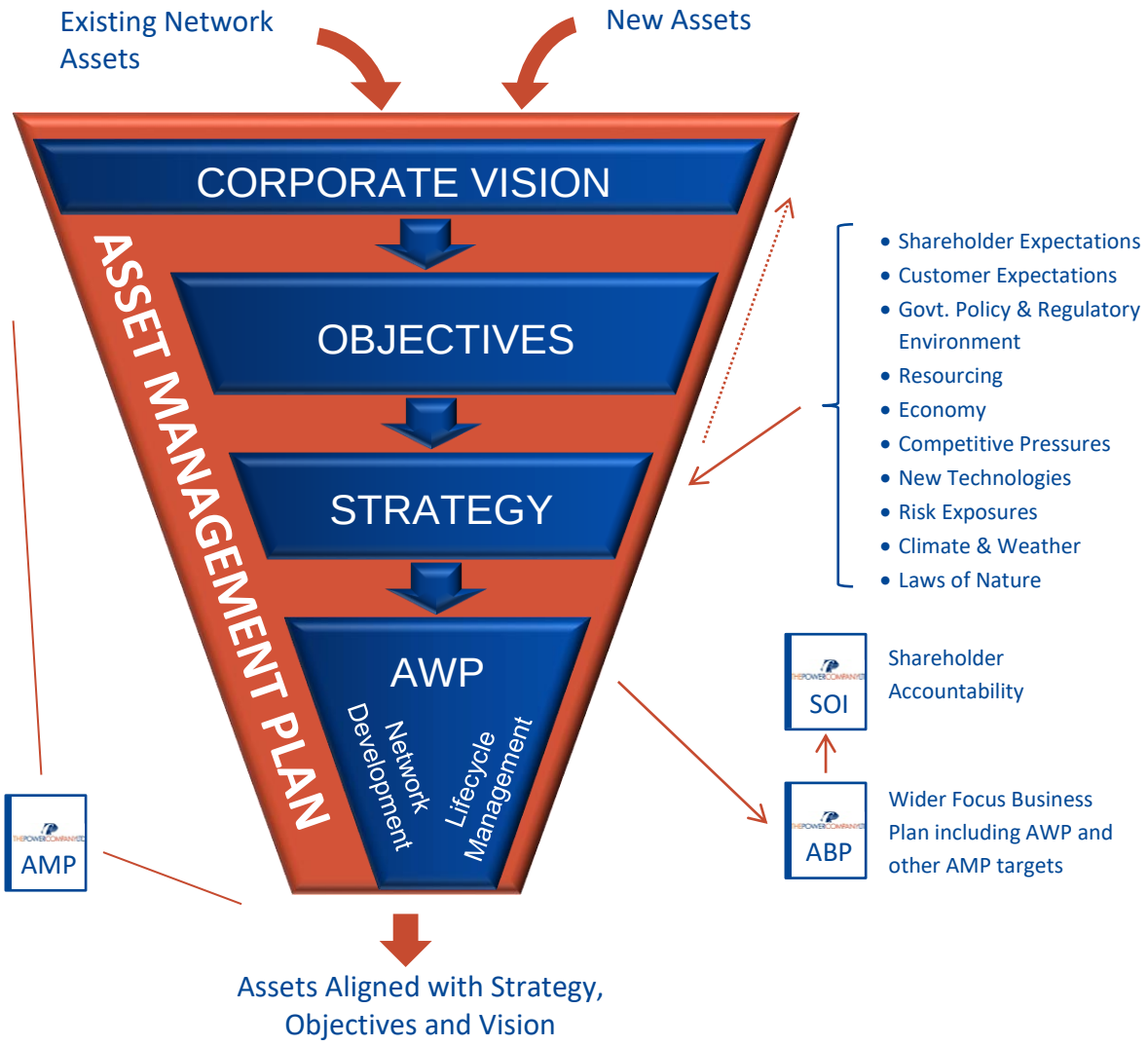


Figure 1: Interaction of Objective, Strategies and Key Plans

1.9. Systems and Information Management

TPCL has a variety of information management tools which capture asset data and can be used to aggregate this data into summary information. A summary of the key data repositories is shown in Table 7.

Table 7: Key Data Repositories

Information System	Data Type	Data Source
Asset Management System (AMS – Maximo)	Description, Age, Condition	Network Equipment Movement (NEM)Forms, Field Survey, Supplier Data, Commissioning Records, Test Records
Geographic Information System (GIS)	Location, Age, Connectivity	As-built information
SCADA	Switch Status, Loading	Polled devices
PowerNet Connect	Customer Details	MARIA registry, GIS
PowerNet Connect	Customer calls regarding faults	Customer calls to System Control
Outage Reporting System	Regulatory recording of outages SAIDI & SAIFI	System Outage Logs
Defect Database	Equipment failures	System Control, Reports from field staff, Project Managers
Risk Manager	Risk management information	System Control and Staff

Data completeness is generally good with a summary of completeness and noted limitations provided in Table 8.

Table 8: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Reasonable	Equipment ages include some estimate by era of manufacture
Condition Assessment Database	Condition	Reasonable	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Reasonable	Some delays between job completion and Maximo update
AMS	Details	Reasonable	Some delays between job completion and Maximo update
AMS	Age	Reasonable	Missing age on old components, mix of installation and manufacturing dates used as age estimate

System	Parameter	Completeness	Notes
AMS	Condition	Poor	Some condition monitoring data (DGA)
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

1.10. Accountabilities and Responsibilities

Accountability at Ownership Level

TPCL has a single shareholder – The SEPS Consumer Trust. The Trust currently has five trustees who collectively possess 68,165,402 shares in TPCL on behalf of the Trust:

- Jim Hargest
- Stuart Baird
- Carl Findlater (Chairman)
- Stephen Canny
- David Rose

The Trust is subject to the following accountability mechanisms:

- By an election process in which two or three trustees stand for election by connected customers every two years. Trustees stand for a term of four years.
- By the Trust Deed which holds all Trustees collectively accountable to the New Zealand judiciary for compliance with the Deed.

Accountability at Governance Level

As TPCL uses PowerNet as their contracted management company to manage the assets there is effectively a two-tier governance structure. The first tier of governance accountability is between TPCL's Board and shareholder with the principal mechanism being the Statement of Intent (SOI). Inclusion of SAIDI and SAIFI targets in this statement makes TPCL's Board intimately accountable to TPCL's shareholder for these important asset management outcomes whilst the inclusion of financial targets in the statement makes TPCL's Board additionally accountable for overseeing the price-quality trade-off inherent in projecting expenditure and SAIDI. TPCL currently have five directors:

- Douglas Fraser (Chairman)
- Duncan Fea
- Don Nicolson
- Wayne Mackey
- Peter Moynihan

The second tier of governance accountability is between TPCL's Board and PowerNet with the principal mechanism being the management contract that specifies a range of strategic and operational outcomes to be achieved.

TPCL Board receives monthly reports that cover the following items

- Network reliability – this lists significant outages over the last month (greater than 100,000 SAIDI minutes) and trends regarding the SOI reliability targets

- Network Quality – detail of outstanding supply quality complaints and annual statistics on them
- Network Connections – monthly and yearly details of connections to the network
- Use of Network – trend of the energy conveyed through the network
- Revenue – detail on the line charges received
- Retailer activity – detail on volumes and numbers per energy retailer operating on the network
- Works Programme – Summary expenditure actuals and forecasts by works programme category with notes on major variations

Large projects with capital budgets exceeding $1,000,000 are required to be supported by a business case explaining the project scope and justification. The business case will generally include a detailed cost-benefit and risk analysis of the recommended scope over alternative options. The business case will form an integral part of the project Charter and staged gate approval process. Variations to projects already in the approved AWP (by more than +10% or -30%), are reported to the Board on a monthly basis.

Accountability at Executive Level

Overall accountability for the performance of the electricity network rests with the Chief Executive of PowerNet. The principal accountability mechanism is the Chief Executive's employment agreement with the PowerNet Board which reflects the outcomes specified in the management contract between TPCL's Board and PowerNet.

Accountability at Management Level

There are eight level two managers reporting directly to PowerNet's Chief Executive with the principal accountability mechanisms being their respective employment agreements.

The individual manager who has the most influence over the long-term asset management outcomes will be the General Manager: Asset Management through his responsibility for preparation of the AMP which will guide the nature and direction of the other managers' work.

Accountability at Operational Level

PowerNet's Network Assets and Major Projects Team (under the General Manager: Asset Management), Operations (Technical) Team and Operations (Distribution) Team respectively manage the major projects, technical projects and distribution projects which make up the AWP. Their objectives are to deliver the AWP projects on time, to scope and to budget while also delivering to the AWP works category and overall CAPEX and OPEX budgets. Major projects typically utilise external consultants and contractors while technical and distribution projects utilise PowerNet's in-house field services.

Where external contractors are required contracts will be utilised, structured on the following mechanisms:

- Purchase Order – generally only minor work
- Fixed lump sum or term service contract – generally on-going work
- Contract – specific project work

Each type details the work to be undertaken, the standards to be achieved, detail of information to be provided and payments schedule.

Accountability at Work-face Level

PowerNet's internal field staff sit and are managed within PowerNet's Operations Team to deliver work divided into technical or distribution projects. External contractors are used for vegetation management (Asplundh) and communications network maintenance and projects (Ventia). Civil works including cable trenching and earthworks for zone substations are typically completed by external contractors. External contractors are also typically used to deliver major projects and occasionally when necessary to supplement workforce capacity or skillsets and include;

- DECOM Limited
- Ventia (formerly known as Broadspectrum Limited)
- Electrix Limited
- Local Electrical Inspectors (M Jarvis, I Sinclair, W Harper)
- Asplundh Tree Expert (NZ) Limited
- Corys Limited
- Consultants (Beca, Edison, Mitton Electronet, ProTechtion Consulting, Mitchell Daysh)

The principal accountability mechanism when utilising these external contractors is through contracts that reflect the outcomes PowerNet must create for TPCL.

Key Reporting Lines

TPCL's ownership, governance and management structure is depicted in Figure 2:

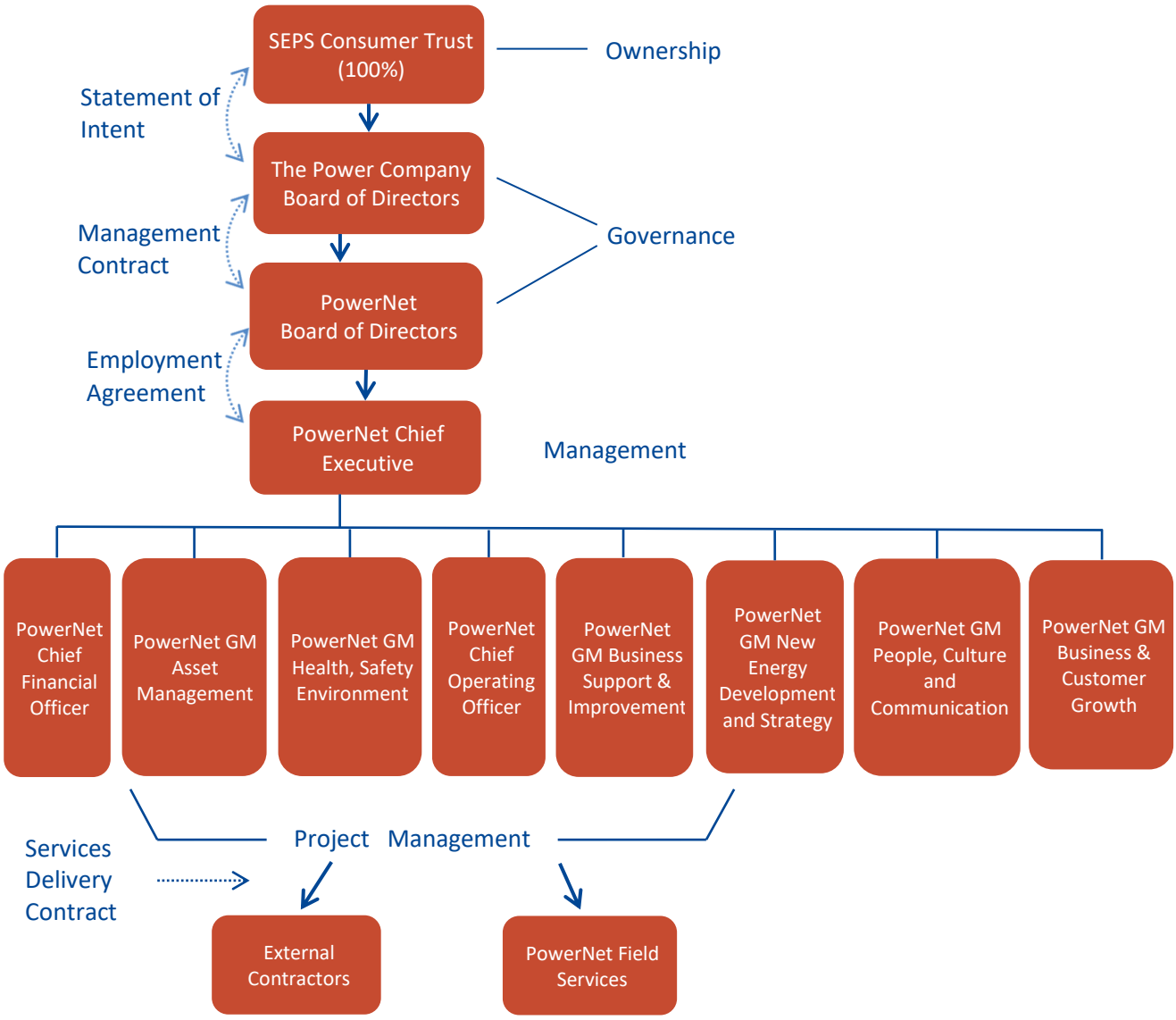


Figure 2: Governance and management accountabilities

Each level of management has defined financial authority limits set out in the PowerNet Financial Authorities Policy. It includes general financial authority levels and increased levels specifically for project work previously approved in the AWP. Generally most projects in the AWP are approved by TPCL Board as part of ABP process in the previous year.

1.11. AMP Communication and Participation Processes

A first draft of the AMP is generally created by November each year and is circulated around management for review and comment. The AWP is developed concurrently as part of the AMP process and has generally been through several revisions by the time it is circulated with the first AMP draft.

Customer perceptions and expectations gauged from surveys and customer consultation evenings are compared with the performance targets set in the previous year's AMP. Any improvements or changes deemed appropriate from this process will be incorporated into the AMP and AWP.

Management and Operations Participation

The planning team is in regular contact throughout the year with those responsible for implementing the current AWP to monitor progress and any variations as they arise. Large capital projects are covered in a formal monthly review meeting. Any changes are consolidated into the initial AWP revision and further revisions are developed in consultation with the management, project managers and field staff who will be involved in its implementation.

Through this consultation the costs and resources for the desired work in the year ahead are estimated. The process tends to be iterative with a level of trade-off reached between what is considered an optimal level of works against realistic expectations of the work force available. “Smoothing” of the year to year works variations is utilised to keep a relatively constant and manageable work stream for both internal and external workforce resources however longer term variations need to be met by adjusting the resources available. Additionally this process tends to be one of moving goal posts as variations generally need to be accounted for up until the information disclosure date.

Governance Participation

The initial consolidated AWP is submitted to TPCL Board supported by a presentation. Any business cases required for large capital projects or other papers covering any novel projects are submitted in advance and will be included in the AWP presentation. After their initial review the Board may request clarifications or changes which are then incorporated into the AWP. These changes tend to be more commercially motivated but will also recognise the need to address any identified health and safety related issues as a high priority. Any recommended changes to the wider AMP that the Board may need to consider, for example strategy updates, may be presented at this stage for review.

The AMP is then updated to reflect changes to the AWP (development planning and lifecycle management) incorporating any other changes required by management before being submitted in full to TPCL Board for review in February. The Board may request further changes to be completed before giving final approval for disclosure at the end of March.

Post Disclosure Communication

During the AMP development process, project scopes are produced for non-routine projects that will be initiated in the next year. These scopes are passed to the relevant project managers to ensure that sufficient detail has been provided for each project in the AWP to proceed in line with the planner’s expectation.

An initial communication meeting is held with internal field staff and invited key contractors to highlight the body of work for the year ahead, especially large or crucial projects. Future years as set out in the AMP are also presented to assist contractors in preparing their resources and their ability to compete for any tendered work in the short to medium term.

Planners are in contact with the project managers throughout the year to monitor progression of the AWP and ensure agreement on any significant variations as design and implementation progresses.

1.12. Assumptions

Planning is based on the assumption that the scenario considered most likely will eventuate, except for ongoing but sporadic (typically reactive) work, where budgets reflect a longer term average. This philosophy is used to minimise variation to performance targets (especially financial) including average performance over the short to medium term. Exceptions are made where the consequences of this

assumption are asymmetric, for example building additional capacity early results in a slight overinvestment whereas building additional capacity too late may have much greater consequences such as equipment damage or inability to supply customer load.

Assumption	Discussion & Implications
Demand growth tracks close to projected rates Demand growth rates (including effects of generation) are discussed in Forecasting Demand and Constraints. The drivers of future demand described are as per the most likely scenario and this section discusses how TPCL manages the risk of different patterns of growth eventuating.	Actual future demands may depart significantly from forecasts. Prediction of demand growth based on "ground-up" analysis is uncertain, due to limited visibility of many variables. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in TPCL's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.
Distributed generation is expected to have little coincidence with network peak demand, and therefore will have little impact on network configuration within the ten year planning horizon	Increased injection of generation, especially during periods of low demand, could create voltage issues. Increased connection requests for distributed generation will require increased resourcing to analyse potential issues arising from connection (particularly safety and voltage)
Electric vehicle adoption rate within forecast, and that consumers will respond well to price signals such that vehicle charging occurs off-peak	Potential to have large impact on network demand with sufficient adoption. If consumers do not respond well to price signals, electric vehicle charging may exacerbate peak demand, triggering greater investment. This effect will be greatest on the suburban LV network in built up urban and semi-urban areas as the upstream MV network generally has sufficient capacity to allow for the forecast increases in load from electric vehicles.
Decarbonisation of industry through process heat conversion towards electricity or biomass fuels	Government has set decarbonisation targets with a 100 percent renewable grid set as an "aspirational goal" by 2035 and a zero emissions economy targeted by 2050. TPCL has approximately 291MW of boiler capacity with 275MW fossil fuelled, generally by coal or diesel. Many of these boilers are used for space heating and therefore heat pumps would be appropriate for conversion. Some process heat requires temperatures beyond what current heat pump technology can deliver so heat pump conversion efficiency has not been considered for these plants. Additional electrical demand would likely be lower than 240-260MW with some proportion opting for biomass conversion. Very limited indications are available on the proportionate conversion to either biomass or electricity. While yet to be confirmed the government intends to set carbon budgets which are expected to be seen as intermediate targets that give some certainty around the trajectory of decarbonisation over the next 30 years. Large scaled projects are handled on an individual basis within contingent projects and are not budgeted within the immediate plan.

	Recent subsidised funding by government invoked interest for the electrification of commercial heat process plants although none came to fruition yet.
Service life of assets, tend towards expected life for the asset type and operating environment	Long term projected service life of asset fleets is based on expected service life for the asset type, operating environment, expected duty, and maintenance practices. Actual replacement and maintenance works are programmed on a near term basis; and are driven by condition and safety for the specific asset. More benign operating environment may increase service life. Investment may be deferred if condition analysis provides reasonable certainty of extended asset life. Harsher environment and/or greater operating duty tends to shorten asset life, requiring consideration for earlier replacement.
No material deviation from historical failure rates	Deterioration of asset reliability compared to expected failure rates, would require accelerated asset replacement (to maintain service levels to customer expectations)
Resourcing is sufficient for projected works programme	Considerable effort has been made to ensure work volumes are deliverable by our key providers. However, unanticipated labour constraints may cause works to be delayed, and/or labour costs to rise.
Little change in safety & work practice regulations	Increases in health & safety requirements will have corresponding increases in cost of works.
Inflation for electricity industry input costs track close to expected (CPI forecasts by Treasury, where specific forecasts unavailable)	Deviation from expected material, labour, overhead input costs, will result in increased costs to works programmes. The projected treatment of network constraints may change, depending on the specific changes to each input cost factor.
Future technologies that may impact work methodologies are not priced into cost estimates	Planning for the inclusion of, currently non-commercial or uneconomic technologies is considered to be imprudent, due to uncertainty of timing, costs, and impacts. Cost savings may occur if technologies develop to a stage where implementation is feasible and economic.
No significant changes in national energy policy	Changes to current national energy policy may affect consumer and/or industry behaviour in such a way that TPCL investment decisions become un-economic.
No significant changes to the shift towards cost-reflective pricing	The Electricity Authority has, in recent publications, signalled an expectation for electricity distributors to progress towards more service-based and cost-reflective pricing. Challenges, from external parties, to pricing reform may cause currently proposed investments to be reconsidered. Changes in low usage fixed charge will not affect total revenue.
No significant changes to requirements regarding resource consenting, easements, land access (private, commercial, local and national authorities)	Increasing requirements are likely to result in increased costs.
No material change to customer expectations of service levels	Changes to customer expectations will require adjustment to service levels and subsequent investments.

No significant changes to local and/or national government development policies	Developmental policies have the potential to affect aggregate and local demand. Investment levels will be adjusted to suit.
Improving industry co-operation	Deterioration in industry co-operation may result in duplicated efforts, miscoordination, and higher costs.
It is assumed that growth will continue to occur at a steady, positive rate in the Northern Southland Area due to increased irrigation. Irrigation combined with more stringent requirements on dairy milk chilling will increase load across pastoral Southland.	Actual future demands may depart significantly from forecasts. Prediction of demand growth based on "ground-up" analysis is uncertain, due to limited visibility of many variables Declining growth rates mean that investments to accommodate previously projected growth are deferred.
Cost impact of equipment size step changes are assumed to remain minor with labour cost being a large proportion of works.	Historic trend expected to continue.
No step changes in underlying growth are considered likely based on historical trending over a long period. Population growth for sizing of equipment is based on the high projection.	Lower population growth may result in some equipment being oversized. Likely impact on total project cost is minor.
Abnormal price movements caused by major external events (war, terrorism, union action, natural disaster) affecting pricing of equipment or labour substantially are difficult to predict and not allowed for in estimates.	These major external events are unable to be predicted with any certainty and TPCL must react accordingly to any changes.
The current line pricing methodology combines a fixed daily charge and a charge per kWh. A new cost reflective line pricing methodology is to be implemented subject to government phasing out of the Low Fixed Charge. Until the changes have been implemented it is difficult to determine the effect any such changes in line pricing will have on consumer behaviour. Therefore, demand forecasts reflect the status quo for line pricing, whilst acknowledging that the future line pricing methodology and subsequent consumer behaviour may impact on these forecasts.	Actual future demands may depart significantly from forecasts. Prediction of demand growth is uncertain due to changing line pricing methodology. Declining growth rates mean that investments to accommodate previously projected growth are deferred. Higher growth rates require adjustment in TPCL's resourcing and/or work scheduling to be able to respond to these opportunities. Visibility is often limited to the near term, particularly for large commercial developments.

1.13. Potential Variation Factors

The following factors have the potential to cause significant variation between the forecasts set out in this AMP and the actual information that will be disclosed in future disclosures:

Cause of variation	Implications
Cost and time estimate inaccuracies	Project cost may vary. Timing may vary, resulting in lower work efficiencies. These may trigger review of project approval if variations are sufficiently large.
Variation in inflation rates and exchange rates	Variable input costs than forecast
Staffing resource losses or inability to recruit as required	Higher cost to be able to meet staffing level required to complete works. This may be coupled with deferment of investment programme, or outright cancellation of certain works if issues become ongoing.
Reactive work varying from that estimated	Deferment of capital or planned maintenance work, if those works are dependent on the asset being in-service. Deferment of capital or planned maintenance work may also arise from staff resourcing constraints.
Equipment failure (especially large capital plant) which may influence future economic options	Greater replacement costs for unplanned failure. Greater costs to maintain supply to customers, until replacement. Review of equipment selection and work methodologies.
New safety issues identified and initiatives created	Variation to labour or material costs. Triggers reviews of work methodologies on existing scheduled works.
Reprioritisation of projects as new work activities are identified	Increased scope, scheduling, design, planning costs if not communicated sufficiently ahead of time. Also requires revision of longer term investment programme.
Detailed analysis of the available options for projects commencing in the short to medium term, which may indicate an alternative approach is preferable to that assumed for long-range forecasting	Similar implications compared to if new work activities are identified.
Greater demand growth than anticipated levels, especially new large industry or customers	May cause certain capital investments to be accelerated, or advanced. May require staffing resources to be re-prioritised to accommodate short term deliverables.
Lower demand growth than anticipated levels, especially loss of existing industry or customers	May cause certain capital investments to be deferred, or cancelled.

2. Assets Covered

This section summarises TPCL's assets and asset configurations, but begins by describing TPCL's geographical coverage, what sort of activities the underlying community uses electricity for, and the issues that are driving key asset parameters such as demand changes.

2.1. Service Areas

TPCL's distribution area broadly covers all of Southland as depicted in Figure 3 except for Bluff and parts of Invercargill that are west of Racecourse Road, south and east of the Waihopai Stream and north of Elizabeth, Moulson and Brown Streets and Tramway Road. TPCL's boundary corresponds with Fiordland National Park to the northwest, Lake Wakatipu to the north and east to the Blue Mountains. This broadly corresponds to the Southland and Gore District Council jurisdictions.

Figure 3: TPCL Distribution Area

Topography varies as follows:

- Flat fertile plains to the immediate east, north and west of Invercargill taking in the towns of Edendale, Wyndham, Mataura, Gore, Winton, Lumsden, Riverton, Otautau and Tuatapere.
- Rolling fertile plains beyond these areas taking in Tapanui, Waipahi, Mossburn, Garston and west towards Te Anau.
- Sparsely populated mountainous areas towards the north-east beyond the rolling fertile plains.
- Uninhabited mountains and bush in the west and north-west of the area.

Key Industries

Key industries within TPCL's network area include sheep, beef and dairy farming, dairy processing, extensive meat processing, black and brown coal mining, forestry, timber processing and tourism. The area's economic fortunes will therefore be strongly influenced by:

- Markets for basic and specialised meats such as beef, mutton and lamb.
- Markets for dairy products.
- Markets for processed timber.
- Markets for black and brown coal.
- Government policies on mining of coal.
- Government policies on forestry and nitrogen-based pastoral farming.
- Access to water for crop and stock irrigation, especially in northern Southland.

The impact of these issues is broadly discussed in Table 9.

Table 9: Impact of key issues

Issue	Visible impact	Impact on TPCL's value drivers
Shifts in market tastes for beef, mutton, and lamb.	May lead to a contraction or expansion of demand by these industries.	Reduces / increases asset utilisation. Possible capacity stranding.
Shifting markets for dairy products.	May lead to a contraction or expansion of demand by these industries.	Reduces / increases asset utilisation. Possible capacity stranding.
Shifting markets for timber.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Shifting markets for coal.	May lead to a contraction in demand by these industries.	Reduces asset utilisation. Possible capacity stranding.
Government CO_2 Policy.	May lead to a contraction or expansion in demand by industries. May create new process requirement for industries.	Reduces asset utilisation. Possible capacity stranding. New capacity required.
Government policy on nitrogen-based farming.	May lead to contraction of dairy shed demand. May lead to contraction of dairy processing demand.	Reduces asset utilisation. Possible capacity stranding.
Access to water.	May lead to increased irrigation demand.	Increases asset utilisation but without corresponding increase in load factor.
Government policy on freshwater quality resulting in restrictions to farming activities	May lead to contraction of dairy processing demand.	Reduce asset utilisation Possible capacity stranding

In the past two years there has been a steady upward trend in dairy product pricing. Due to the impact of COVID-19 on general supply chain process, producers have seen a reduction in price although the

quantum of products exported increased year on year. Major customers that have significant impact on network operations or asset management priorities are:

- Meridian White Hill Wind Farm embedded generation with varying export of up to 58MW.

- Fonterra Co-operative Group Limited dairy plant, Edendale - three 33kV cables each supplying an 11½/23MVA 33/11kV power transformer (N-1 requirement[1]).

- Alliance Group Limited, freezing works at Lorneville and Mataura – generally one or two exclusive 11kV feeders (N-1 requirement).
- Bright Wood NZ Limited, sawmill at Otautau – exclusive 11kV feeder from substation.
- Craigpine Timber Limited, sawmill at Winton – supplied off local feeder.
- Niagara Sawmilling Co Limited sawmill at Kennington – supplied off local feeder for industrial area.
- Lindsay & Dixon Limited, sawmill at Tuatapere – supplied off local feeder.
- Blue Sky Meats Limited, freezing works at Morton Mains – supplied off local feeder but requires regulators at Edendale Hill and Morton Mains on the main supply route and a backup supply from Kennington through one regulator. Has an automatic change-over control of supplying switches at connection point to the network (N-½ requirement[2]).
- Open Country Dairy, at Awarua – supplied off two local feeders (N-1 requirement) at 11kV. The 33kV supply Open Country Dairy being a radial supply with no backup capacity.

[1] N -1 is defined as a full redundant supply so that full load can be supplied from two separate routes.

[2] N-½ is defined as a change-over scheme to an alternative supply but with a short interruption.

- South Pacific Meats, at Awarua – supplied off local feeder with switched backup (N-½ requirement[3]).
- Balance Agri-Nutrients Limited, at Awarua – supplied off local feeder.
- Silver Fern Farms Limited:
    - Venison abattoir at Kennington – supplied off local feeder.
    - General abattoir at Gore – supplied off local feeder.
- Various Hotels and Motels in Te Anau – supplied off local township feeders with backup capability from other township feeders.
- Pioneer Generation, hydro generator at Monowai – connected onto 66kV ringed network (N-1 requirement).
- Southern Generation Limited Partnership, windfarm at Flat Hill – exclusive 11kV feeder at Bluff.
- South Wood Export Limited, chip mill at Awarua – exclusive 33/11kV 5MVA power transformer due to large synchronous chipper motor.
- Southern District Health Board, hospitals at Invercargill and Gore – supplied off township feeders with alternatives from other township feeders.

Load Characteristics

Domestic: Standard household demand peaks in the morning (8am) and evening (6:30pm).The average energy consumption by residential customers are typically flat with relative small variation annually. The main contributing factor to the change in the annual average consumption per residential customer is seasonal changes, resulting on consumption variations due to consumer behaviour. Peaks normally occur in the winter months as heating requirements increase. A typical daily domestic load profile and a typical annual domestic load profile are shown in Figure 4 and Figure 5 respectively.

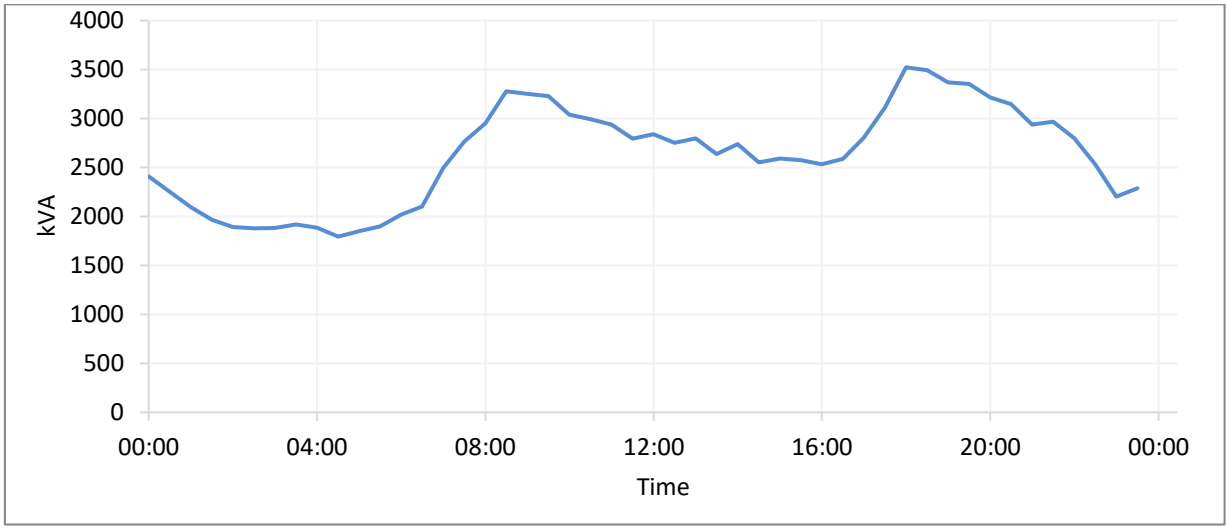


Figure 4: Typical Domestic Daily Load Profile (9 July 2020, Waikiwi CB3)

[3] N-½ is defined as a change-over scheme to an alternative supply but with a short interruption.

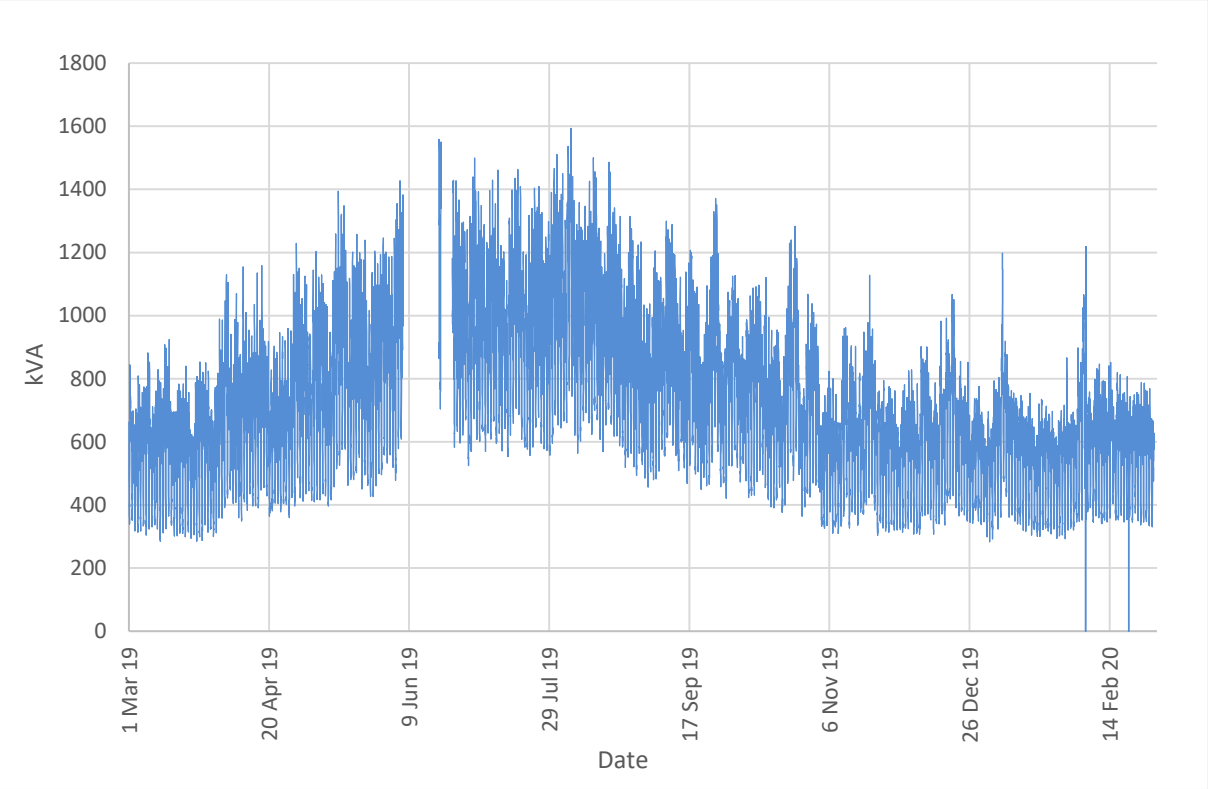


Figure 5: Typical Domestic Feeder Yearly Load Profile (North Gore 4)

Farming: Normally only very low usage with some pumps and electric fences, with peak usage during the few days of shearing or crop harvesting.

Dairy: Milking season between August and May with morning and late afternoon peaks. A typical daily milking load profile is shown in Figure 6.

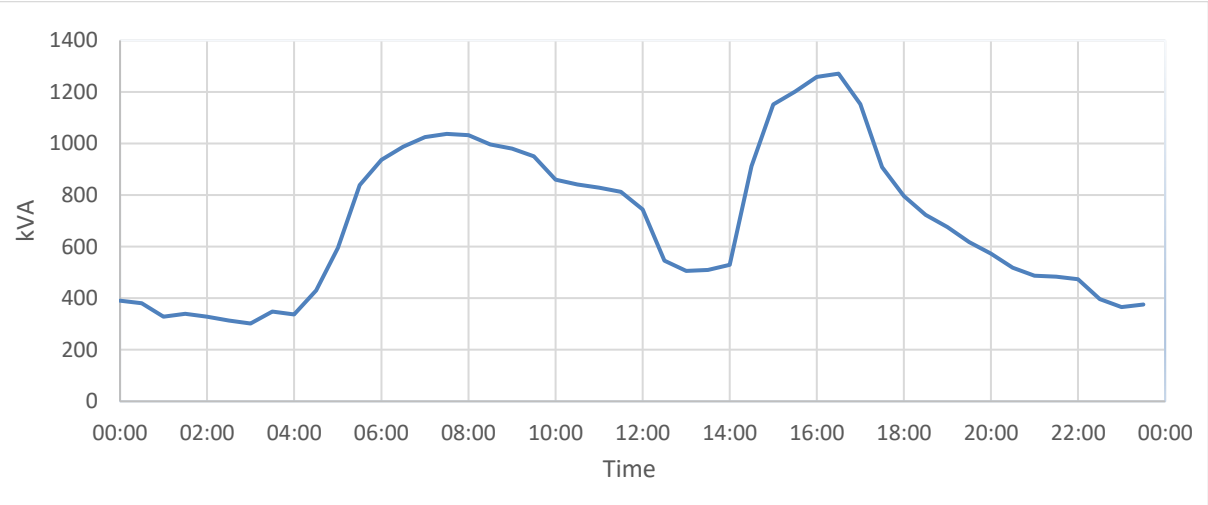


Figure 6: Typical Daily Milking Load Profile (02 October 2019, Centre Bush CB2)

Sawmills: Usage at sawmills due to processing and kiln drying of product. Some wood-chipping of logs for export, and these have some very large motors with onerous starting characteristics.

Dairy Processing: Load characteristic is dependent on milk production with the 'flush' occurring in late October. One plant has 3.8 MW of cogeneration, which can create peaks if it is off. A typical annual dairy processing plant profile is shown in Figure 7.

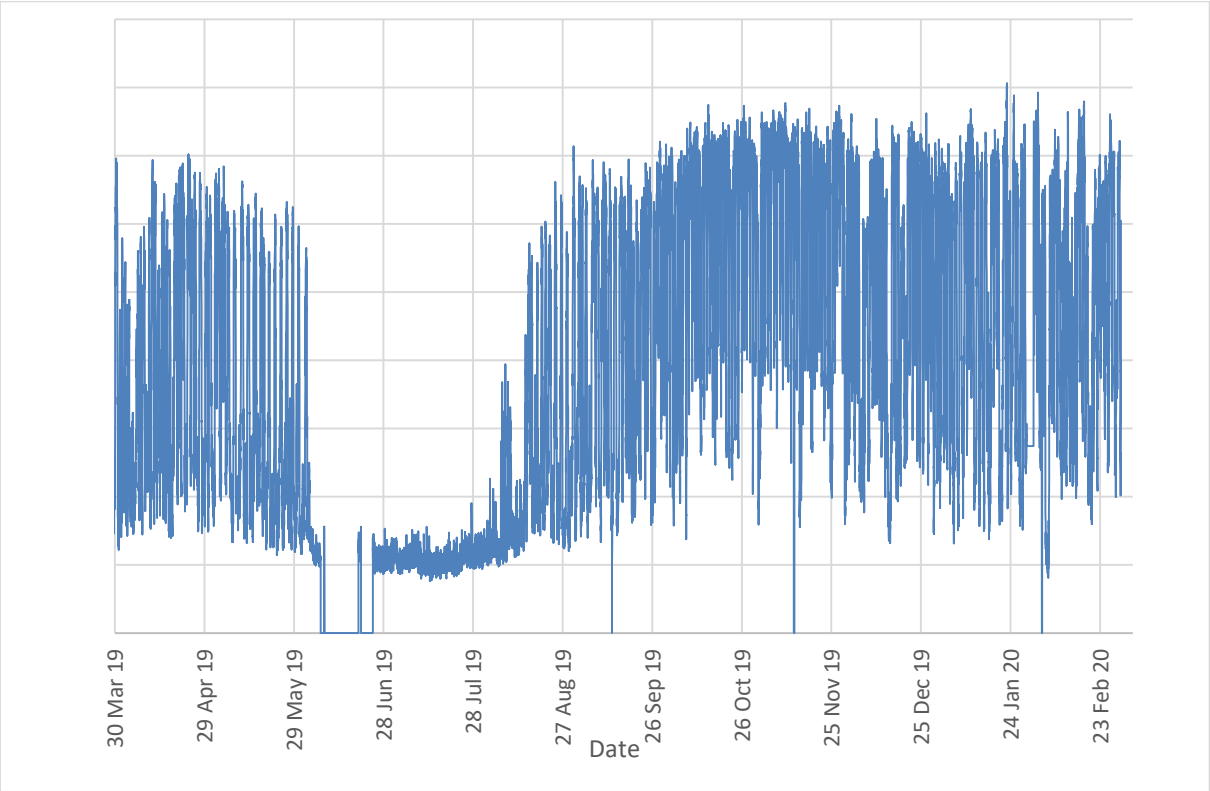


Figure 7: Dairy Processing Plant annual load profile

Energy and Demand Characteristics

Key energy and demand figures for the year ending 31 March 2020 are as shown in Table 10.

Table 10: Energy and Demand

Parameter	Value	Long-term trend
Energy Conveyed	787.55 GWh	Steady Growth +0.5-1.5%
Maximum Demand[4]	146.72 MW	Steady
Load Factor	61.3%	Steady
Losses (actual)	5.8%	Steady

It is particularly hard to extract underlying growth rates from historical data as both maximum demands and total energy conveyed, as recorded for any year, are heavily dependent on the weather. This variation tends to swamp the effect of the relatively low growth rates. Mathematical treatment such as "best fit" curve application yields completely different results when applied to different time periods i.e. previous 5 years, 10 years, 20 years etc. Shorter time periods giving meaningless results due to huge variation between inclusion and exclusion of a particular year (say between 4 years trend or 5 years trend) and longer time periods do not account for recent trends. Growth rates therefore tend to reflect "gut feel" more than anything and accordingly certainty with the growth rates shown in Table 10 is low. Forecasting Demand and Constraints looks at the analysis, trending and forecast of growth for TPCL.

2.2. Network Configuration

To supply TPCL's 36,436 customers TPCL owns and operates an electrically contiguous networks which is supplied by Four Grid Exit Points (GXP) at Invercargill, North Makarewa, Gore and Edendale and by up to 72MW of injected Generation from Meridian's White Hill wind farm, Pioneer Generation's Monowai hydro station and Southern Generation Limited Partnership's Flat Hill wind farm.

Bulk Supply Points and Embedded Generation

Invercargill GXP

Invercargill GXP comprises a strong point in the 220kV grid which is tied to Roxburgh and Manapouri power stations and to the North Makarewa GXP. Invercargill is also a major supply node for the Tiwai Point Smelter.

The 33kV supply arrangement at Invercargill comprises an indoor switchboard that is energised by two three-phase 120MVA 220/33kV transformers. There are eleven 33kV feeders each supplied through its own circuit breaker. TPCL takes supply from six of these feeders in normal operation. Back up supplies are available from other TPCL feeders and are used from time to time.

TPCL owns the segments of 33kV line (but not the circuit breakers or bus) that run within the GXP land area and also accommodates a backup control room for PowerNet's System Control. TPCL also owns one of the two 33kV 216⅔Hz ripple injection plants on the west side of the GXP site. The second plant is owned by Electricity Invercargill Limited (EIL) with each providing backup capability to the other.

[4] This is different from the sum of the individual demands at each GXP, which will be greater than the coincident demand due to diversity.

North Makarewa GXP

North Makarewa is also a strong point in the 220kV grid which ties to Manapouri power station, Invercargill and Three Mile Hill GXP's and to the Tiwai Point smelter. The company takes supply from North Makarewa at 33kV from two 30/60MVA transformers.

TPCL owns the following assets within the GXP land area:

- Two 33/66kV 30/40MVA step-up transformers.
- One Neutral Earthing Resistor (NER).
- Oil containment and separator system.
- Nine 66kV circuit breakers.
- Four 66kV 5MVAr capacitor banks.
- 66kV bus.
- Six 33kV circuit breakers (but not the incoming 33kV circuit breakers or 33kV bus)
- One 33kV 216⅔Hz ripple injection plant on the southwest side of the GXP site, with backup provided from the 66kV 216⅔Hz ripple injection plant at Winton.

Edendale GXP

Edendale GXP is supplied by two 110kV single-circuit pole lines from Gore GXP via Brydone GXP and from Invercargill GXP. TPCL takes supply to its 33kV bus at Edendale by two incomers from two 30MVA transformers. Seven 33kV feeders, a 33kV bus coupler, 33kV cables and lines within the GXP land area are owned by TPCL.

The company also owns one 33kV 216⅔Hz ripple injection plant on the north side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Gore.

Gore GXP

Gore GXP is supplied by three 110kV single circuit pole lines, from Roxburgh power station, Invercargill GXP via Edendale and Brydone and interconnected to Berwick and Halfway Bush GXP's. TPCL takes supply from the two 110/33kV 30MVA transformers at Gore to six 33kV feeders. TPCL owns the segments of 33kV line and cable (but not the circuit breakers or bus) within the GXP land area. Gore GXP has a 220kV interconnector between North Makarewa GXP and Three Mile Hill.

The company also owns one 33kV 216⅔Hz ripple injection plant on the south side of the GXP site, with partial backup provided from the 33kV 216⅔Hz ripple injection plant at Edendale.

Table 11: TPCL Bulk Supply Characteristics

	Voltage	Rating	Firm Rating	Maximum Demand 2019/20	LSI[5] Coincident Demand 2019/20
Invercargill GXP	220/33kV	240MVA	141MVA	94.874MW / 99.618MVA (05/08/2019 09:30)	80.407MW / 84.427MVA (23/08/2019 08:00)
TPCL	*(GXP assets shared with EIL)*			38.164MW / 40.072MVA (23/10/2019 08:00)	33.39MW / 35.060MVA (06/08/2018 07:30)
North Makarewa GXP	220/33kV	120MVA	67MVA	49.374MW / 51.843MVA (09/09/2019 08:00)	44.412MW / 46.633MVA (23/08/2019 08:00)
Gore GXP	110/33kV	60MVA	37MVA	30.156MW / 31.664MVA (16/05/2019 08:30)	22.252MW / 23.365MVA (23/08/2019 08:00)
Edendale GXP	110/33kV	60MVA	34MVA	27.422MW / 28.793MVA (16/01/2020 17:00)	11.548MW / 12.125MVA (23/08/2019 08:00)
White Hill Generation	66kV	56MVA	0MVA	48.864MW / 51.307MVA (11/12/2019 08:30)	0.606MW / 0.636MVA (23/08/2019 08:00)
Monowai Generation	66kV	7.5MVA	5MVA	6.408MW / 6.728MVA (11/10/2019 14:30)	4.455MW / 4.678 MVA (23/08/2019 08:00)
Flat Hill Generation	11kV	6.8MVA	0MVA	7.194MW / 7.554MVA (16/08/2019 12:30)	4.488MW / 4.712MVA (23/08/2019 08:00)
Mataura Generation	11kV	0.9MVA	0MVA	0.812MW / 0.853MVA (10/07/2019 13:00)	0.776MW / 0.815MVA (23/08/2019 08:00)

There is significant generation embedded within TPCL's network, as covered in the table above. A number of smaller distributed generation connections exist but are only a few kW each in size. These generators are generally installations which due to their generation profiles (tied to sunlight conditions) have negligible effect on GXP loading.

Subtransmission

TPCL's subtransmission network is a meshed electrical network that takes supply from four GXP's at Invercargill, North Makarewa, Edendale and Gore as depicted in Figure 8.

[5] LSI = Lower South Island

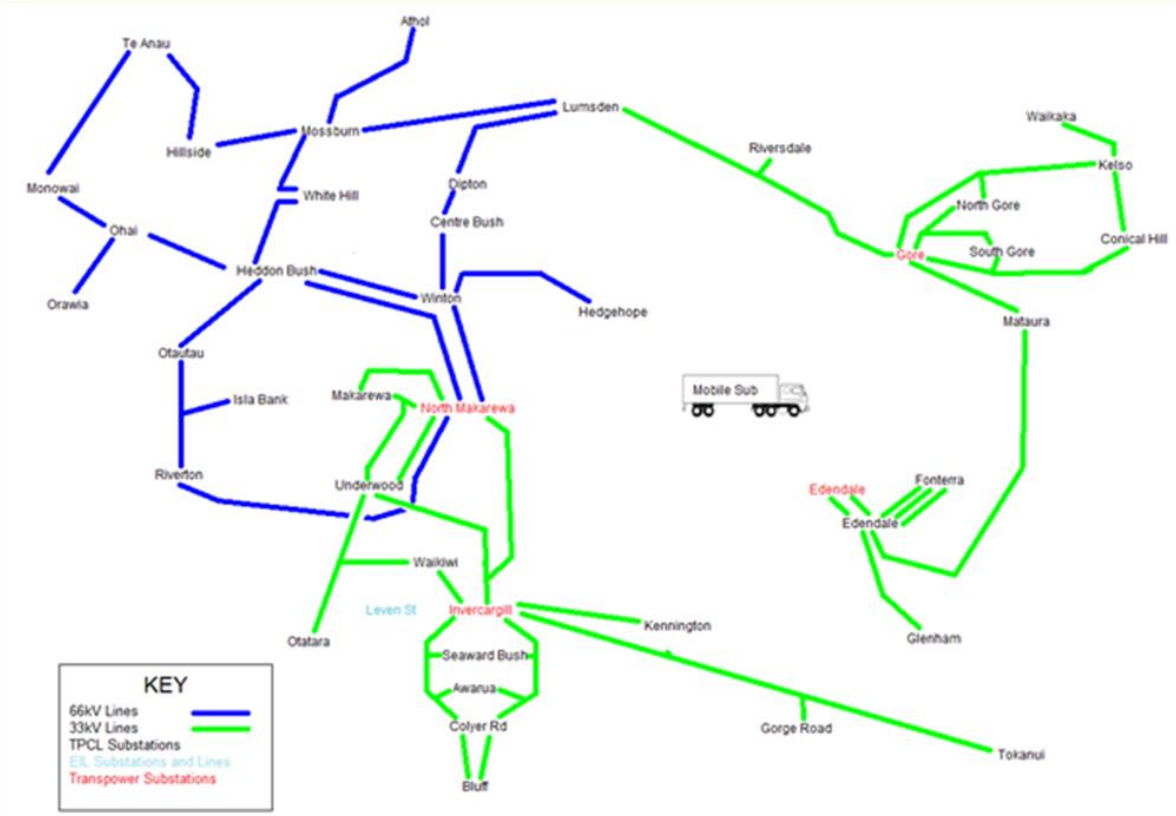


Figure 8: Subtransmission network

The subtransmission network comprises 505km of 66kV line, 387km of 33kV line, and 12km of 33kV cable and has the following characteristics:

- It is almost totally overhead except for cable runs near GXP's and zone substations. Larger runs of cable include the inter-connects to Electricity Invercargill's Leven Street and Southern zone substations which are cabled from TPCL's Otatara and Seaward Bush lines respectively, short sections of 33kV around corners on the Invercargill to Kennington 33kV circuit, the supply cables to Edendale Fonterra, and connections from the Bluff lines into Colyer Road.
- It includes three different electrical topologies (ring, ladder and spur) as well as an interconnection of 66kV and 33kV at the North Makarewa GXP and at TPCL's Lumsden substation.
- It includes a large number of lightly-loaded zone substations because the long distances and loads are beyond the reach of 11kV.

Zone Substations

TPCL owns and operates the following 37 zone substations across Southland. TPCL also takes an 11kV supply for two feeders supplied from EIL's Racecourse Road substation to supply TPCL customers in areas at the eastern edge of Invercargill. Descriptions for TPCL's zone substations are given in Table 12 including zone substation security classifications.

Table 12: TPCL's Zone Substations

Zone Substation	Nature of Load	Description of substation	Security Classification
Athol	Villages of Athol and Kingston, rural farms with summer irrigation.	66kV line from Mossburn onto a 66kV circuit breaker and 66/11+11kV 3/5MVA transformer supplying an indoor 22kV rated switchboard with two 11kV feeders.	A(I)
Awarua	Single large industrial customer.	Simple outdoor site with two 33/11kV 5MVA transformers and associated outdoor 33kV and 11kV circuit breakers.	A(ii)
Bluff	Predominantly urban domestic load in Bluff, but including one large and a few medium industrial customers. One large windfarm with exclusive 11kV feeder.	Medium complexity outdoor substation with two 33/11kV 6/12MVA transformers, these supply an indoor 11kV switchboard with four feeders.	AAA
Centre Bush	Predominantly rural load in the middle of the Southland Plains.	Simple tee connected 66/11+11kV 5/7.5MVA transformer with four 11kV feeders.	A(i)
Colyer Road	Predominantly three large industrial customers with some minor rural load to the south-west.	Substantial two 33/11kV 6/12MVA transformer substation with (n-1) supply. Indoor 33kV switchboard with seven circuit breakers. Indoor 11kV switchboard with four feeders.	AAA
Conical Hill	Predominantly rural load. Old sawmill next to site, which has been moth-balled.	Large outdoor substation with 33kV circuit breakers on two incoming supplies from Gore via South Gore substation and also from Gore via Kelso substation. Two 33/11kV 5MVA transformers supply a full outdoor 11kV structure with incomer circuit breakers and four feeders.	AAA
Dipton	Predominantly rural load in the north of the Southland Plains.	Simple tee connected 66/11+11kV 3/5MVA transformer with two 11kV feeders.	A(i)
Edendale Fonterra	Huge dairy factory with four large milk powder plants and other milk process plants.	Triple 33kV cable and 33/11kV 11.5/23MVA transformers supply to the Fonterra 11kV switchboards.	AAA
Edendale	Rural towns of Edendale and Wyndham, small meat works at Morton Mains and rural farms.	Full 33kV switchboard with seven feeder circuit breakers, two supply the local two 33/11kV 6/12MVA transformers, three to Edendale Fonterra, one to Glenham and one to Mataura. An indoor 11kV switchboard with seven feeders.	AAA
Glenham	Glenham village, rural farms.	33kV line from Edendale onto a 33kV circuit breaker and 33/11kV 1.5MVA transformer with two outdoor 11kV feeders.	A(i)
Gorge Road	Gorge Road village, rural farms.	33kV line from Invercargill that continues on to supply Tokanui via a 33kV line circuit breaker. Substation has simple tee into single 33kV CB. 33kV bus branches into two motorised switches onto dual	A(i)

Zone Substation	Nature of Load	Description of substation	Security Classification
		33/11kV 1.5MVA transformers. Indoor 11kV switchboard with three 11kV feeders.	
Heddon Bush	Switching station.	Large outdoor 66kV switchyard. Has two 66kV supply routes from North Makarewa, supplies two ends of the North-western 66kV ring and has a 66kV link to Mossburn via White Hill.	AA
Hedgehope	Hedgehope Village, rural farms	66kV line from Winton onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with three 11kV feeders.	A(i)
Hillside	The Key village, rural farms.	Medium outdoor substation supplied by two 66kV lines with 66kV circuit breakers, a single 66/11kV 2.25MVA transformer, three single phase voltage regulators, and three outdoor 11kV feeders.	A(i)
Isla Bank	Villages of Drummond and Isla Bank, rural farms	66kV line teed off the Riverton – Heddon Bush 66kV onto a 66kV circuit breaker and 66/11+11kV 5MVA transformer supplying an indoor 22kV switchboard with three 11kV feeders.	A(i)
Kelso	Tapanui township, rural farms.	Medium outdoor 33kV structure with two supplying lines from Gore and a 33kV feeder to Waikaka. Single 33/11kV 5MVA transformer with incomer circuit breaker and four 11kV feeders.	A(i)
Kennington	Industrial area with various manufacturing process and few residences, Woodlands village, rural farms.	Medium outdoor 33kV structure with single 33kV line from Invercargill. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with three 11kV feeders.	A(ii)
Lumsden	Lumsden township, rural farms with summer irrigation.	A 66kV substation which forms part of the Northern 66kV ring. There is a normally open link to Riversdale via a 66/33kV transformer. There is a single 66/11+11kV 5MVA transformer supplying four 11kV feeders.	A(i)
Makarewa	Rural farms with industrial plant.	Medium outdoor 33kV structure with two supplying lines from North Makarewa. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with five 11kV feeders.	AAA
Mataura	Township of Mataura, major Meat Processing Plant and rural farms.	Medium outdoor 33kV structure with main supplying line from Gore GXP, with a backup line to Edendale, and four 33kV circuit breakers. Two 33/11kV 10MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders.	AA

Zone Substation	Nature of Load	Description of substation	Security Classification
Monowai	Remote rural farms.	Medium outdoor 66kV yard with three 66kV circuit breakers. A single 66/11kV 1MVA transformer supplying one 11kV feeder.	A(ii)
Mossburn	Village of Mossburn, small Meat Processing Plant and rural farms.	Large outdoor 66kV yard with five 66kV circuit breakers. A 66/33kV 30/40MVA transformer supplying load via a 3MVA 11kV tertiary winding. (This is a spare for NMK). Outdoor switchboard with incomer circuit breaker and four 11kV feeders. Two 66kV lines as part of North-western 66kV Ring. A 66kV feeder to Athol and a 66kV line to Lumsden.	A(i)
North Gore	Town of Gore and rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV transformers (10MVA and 10/20MVA) supplying an indoor 11kV switchboard with four 11kV feeders.	AAA
Ohai	Town of Ohai and rural farms. Supplies one open-cast coal mine.	Large 66kV structure with lines from North Makarewa GXP, via Winton and Heddon Bush and to Monowai Power Station. Also supplies a 66kV feeder to Orawia. Each circuit is protected by a 66kV circuit breaker. One 66/11kV 5/7.5MVA supplying an indoor 11kV switchboard with four feeders.	AA
Orawia	Town of Tuatapere and village of Orawia, rural farms and sawmills at Tuatapere.	66kV line onto a 66kV circuit breaker and 66/11kV 5/7.5MVA transformer supplying an outdoor 11kV structure with incomer circuit breaker and four 11kV feeders.	A(i)
Otatara	Town of Otatara and a few farms.	33kV line from Invercargill into simple outdoor substation with single 33/11kV 5MVA transformer supplying an outdoor 11kV structure with incomer circuit breaker and three 11kV feeders. An 11kV alternative supply is available from EIL.	A(i)
Otautau	Town of Otautau, large sawmill, rural farms.	Medium 66kV structure with lines from North Makarewa GXP via Heddon Bush and Riverton. These lines tee onto a single 66kV circuit breaker supplying one 66/11kV 5/7.5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and five feeders.	A(i)
Racecourse Road (EIL)	Eastern area next to Invercargill city, mix of urban, lifestyle blocks and rural. Includes major Hotel/Motel complex.	Two 11kV feeders from the indoor switchboard at Electricity Invercargill Ltd Racecourse Road substation.	A(i)

Zone Substation	Nature of Load	Description of substation	Security Classification
Riversdale	Town of Riversdale, village of Waikaia and rural farms, some with summer irrigation.	Small outdoor 33kV structure with main supplying line from Gore, with a back line to Lumsden. Single 33kV circuit breaker and 33/11kV 5MVA transformer. Outdoor 11kV structure with incomer circuit breaker and four 11kV feeders.	A(i)
Riverton	Town of Riverton, small fish processing, rural farms	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 5/7.5MVA transformers. Part of southern 66kV ring supplied from North Makarewa. Indoor 11kV switchboard with six feeders.	AAA
Seaward Bush	South Invercargill, Southland Hospital, Fertilizer plant, Wastewater treatment plant, rural Farms.	Medium complexity outdoor substation with two 33/11kV 10MVA transformers, these supply an indoor 11kV switchboard with five feeders. Two 33kV lines from Invercargill GXP.	AAA
South Gore	Town of Gore, small meat processing plant, rural farms.	Medium outdoor 33kV structure with two main supplying lines from Gore GXP. Two 33/11kV 6/12MVA transformers supplying an indoor 11kV switchboard with four 11kV feeders. One 33kV line continues onto Conical Hill substation.	AAA
Te Anau	Towns of Te Anau and Manapouri, rural farms.	Large 66kV structure with two 66kV circuit breaker supplying two 66/11kV 9/12MVA transformers. Part of northern 66kV ring supplied from Heddon Bush. Indoor 11kV switchboard with five feeders.	AAA
Tokanui	Villages of Waikawa, Fortrose, Curio Bay and Tokanui, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer. Outdoor 11kV structure incomer circuit breaker and two 11kV feeders. 33kV line from Invercargill via Gorge Road.	A(i)
Underwood	Major Meat processing plant, town of Wallacetown, rural farms.	Large 33kV structure with three 33kV circuit breakers, supplying two 10/20MVA transformers. An indoor 11kV switchboard with four feeders. Two 33kV Lines from North Makarewa GXP and two from Invercargill GXP. Provides a backup to the EIL Leven St substation off one of the Invercargill lines so that Leven St can be supplied from North Makarewa GXP.	AAA
Waikaka	Village of Waikaka, rural farms.	Simple outdoor single 33/11kV 1.5MVA transformer, single 33kV circuit breaker with one 11kV feeder. Single 33kV line from Kelso.	A(i)

Zone Substation	Nature of Load	Description of substation	Security Classification
Waikiwi	Mix of urban residential and urban light industrial load in northern suburbs of Invercargill.	Substantial two 33/11kV 11.5/23MVA transformer substation with (n-1) supply including possibility of supply from two different GXP's. Indoor 33kV switchboard with five circuit breakers. Indoor 11kV switchboard has four feeders.	AA
Winton	Town of Winton, Villages of Lochiel and Browns, Large Sawmill, Limeworks, rural farms.	Winton is on the southern 66kV ring supplied from North Makarewa, with two lines from North Makarewa and Heddon Bush. Two 66/11kV 6/12MVA transformers supplying a full indoor 11kV switchboard with seven feeders.	AAA

Distribution Network

In rural areas the configuration is mainly meshed between substations with reasonable backup capability. Most distribution off this main distribution is radial with only some meshing.

In urban areas a high degree of meshing between 11kV feeders is possible.

The 11kV distribution network construction is as follows:

- Rural areas are predominantly concrete pole, flat construction with wooden cross-arms and pin insulators.
- Suburban areas are either concrete pole with wooden cross-arms and pin insulators or PILC[6] or XLPE[7] cable.
- CBD areas tend to be PILC cable unless this has been replaced, which will almost always be with XLPE cable.

TPCL's split of 11kV distribution network on a per substation basis is presented in Table 13. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 13: 11kV Distribution network per substation

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	121.46	3.17	500	4.01
Awarua	0	0.07	1	14.29
Bluff (TPCL)	33.18	0.4	153	4.56
Centre Bush	274.38	0.19	646	2.35
Colyer Road	13.85	4.89	42	2.24
Conical Hill	165.62	0.25	298	1.80
Dipton	160.26	0.27	317	1.97

[6] PILC = Paper Insulated Lead Covered – a standard underground cable construction format.

[7] XLPE = Cross-Linked Polyethylene – the modern underground cable construction format.

Edendale Fonterra	0	0	1	0.00
Edendale	295.69	4.14	1380	4.60
Glenham	192.48	0	349	1.81
Gorge Road	164.52	0.26	388	2.35
Hedgehope	138.6	0.15	310	2.23
Hillside	226.77	2.27	364	1.59
Isla Bank	132.68	1.4	351	2.62
Kelso	441.27	0.38	1289	2.92
Kennington	174.1	3.48	764	4.30
Lumsden	311.4	5.19	827	2.61
Makarewa	245.66	2.22	1094	4.41
Mataura	233.96	3.64	1244	5.24
Monowai	47.19	0.37	94	1.98
Mossburn	208.26	2.28	462	2.19
North Gore	284.02	5.02	2737	9.47
Ohai	214.65	0.47	768	3.57
Orawia	316.56	3.03	940	2.94
Otatara	61.34	5.34	1341	20.11
Otautau	189.33	1.09	844	4.43
Racecourse Road (TPCL)	28.67	2.83	482	15.30
Riversdale	424.37	3.13	1332	3.12
Riverton	293.77	8.70	2094	6.92
Seaward Bush	150.89	6.32	2479	15.77
South Gore	196.37	21.17	2495	11.47
Te Anau	174.86	39.35	2575	12.02
Tokanui	229.95	0.69	567	2.46
Underwood	66.20	1.49	602	8.89
Waikaka	108.69	0.19	252	2.31
Waikiwi	96.03	11.83	3479	32.25
Winton	394.75	8.01	2525	6.27
Unallocated	0.21	1.03	51	41.13
			Average	**7.07/km**

Distribution Substations

Just as zone substation transformers form the interface between the sub-transmission and the 11kV distribution networks, distribution substations form the interface between the 11kV distribution and 400V distribution networks. The distribution substations range from 1-phase 0.5kVA pole-mounted transformers to 3-phase 1,500kVA ground-mounted transformers supplied via circuit breaker ring main units. These larger substations typically supply special customers, like the Open Country Dairy processing plant at Awarua.

Table 14 shows distribution transformer numbers by rating.

Table 14: Number of distribution substations

Rating	Pole	Ground
1-phase up to 15kVA	4756	29
1-phase 30kVA	430	11
1-phase 50kVA	13	1
3-phase up to 15kVA	1962	3
3-phase 30kVA	1787	44
3-phase 50kVA	981	43
3-phase 75kVA	284	13
3-phase 100kVA	203	82
3-phase 200kVA	108	214
3-phase 300kVA	48	110
3-phase 500kVA	3	44
3-phase 750kVA	3	22
3-phase 1,000kVA	1	11
3-phase 1,500kVA		12
Total	**10579**	**639**

Each distribution transformer has medium voltage (MV) protection generally provided by fuses but some larger units by circuit breakers controlled by basic overcurrent and earth fault relays. This is generally applied as individual protection for each site. Group protection is used where a single fuse is located at the take-off from the main feeder line, with up to five downstream units. Each individual unit will have MV isolation where the dropout fuse is replaced with a solid link. This is done to speed fault restoration as fault staff can locate the faulty 'group' as the dropout is generally on the main road and check which unit is failed before restoration.

Low voltage protection is by DIN[8] standard High Rupture Capacity (HRC) fuses sized to protect overload of the distribution transformer or outgoing LV cables.

Low Voltage Network

The 230/400V Low Voltage (LV) network is predominantly clustered around each distribution transformer. The coverage of each individual distribution transformer tends to be limited by volt-drop to about a 200m radius.

The LV network is almost solely radial in rural areas but meshed in urban areas which provide some restoration of supply after faults and for planned work. Transformer loading and volt drop tend to be the limiting factors in utilising these backups.

Construction of TPCL's LV network varies considerably and can include the following configurations:

- Overhead LV (including underbuilt on 11kV and underbuilt on 33kV and 66kV) using the following conductors;

[8] Deutsches Institut für Normung e.V. (DIN; in English, the German Institute for Standardization) is the German national organization for standardization and is that country's ISO member body.

- Open Wire
- Aerial Bundled Conductor (ABC)
- Covered
- Aerial Neutral Screen
- PILC cables only.
- XLPE cable only.
- Conjoint PILC – XLPE cable.

TPCL's split of LV network on a per substation basis is presented in Table 15. Safety and reliability are TPCL's strongest drivers for allocation of resources, with customer density providing an indication of priority of other works.

Table 15 Low Voltage network per substation

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Athol	8.43	2.77	500	44.64
Awarua	0	0	1	
Bluff	5.72	0.09	153	26.33
Centre Bush	15.60	0.42	646	40.32
Colyer Road	0.49	0.34	42	50.60
Conical Hill	8.55	0.15	298	34.25
Dipton	8.23	0.85	317	34.91
Edendale Fonterra	0	0	1	
Edendale	47.97	1.76	1380	27.75
Glenham	12.91	0.11	349	26.80
Gorge Road	14.98	0.14	388	25.66
Hedgehope	10.34	1.05	310	27.22
Hillside	3.79	0.4	364	86.87
Isla Bank	11.35	0.29	351	30.15
Kelso	31.69	1.67	1289	38.64
Kennington	31.46	1.97	764	22.85
Lumsden	17.59	2.30	827	41.58
Makarewa	43.78	1.80	1094	24.00
Mataura	31.19	1.79	1244	37.72
Monowai	1.18	0.64	94	51.65
Mossburn	7.93	1.05	462	51.45
North Gore	57.25	11.11	2737	40.04
Ohai	26.24	0.32	768	28.92
Orawia	28.98	2.91	940	29.48
Otatara	29.16	12.13	1341	32.48
Otautau	23.83	3.34	844	31.06
Racecourse Road (TPCL)	9.60	7.52	482	28.15
Riversdale	34.8	1.29	1332	36.91
Riverton	62.81	6.25	2094	30.32
Seaward Bush	42.41	25.33	2479	36.60
South Gore	45.69	15.07	2495	41.06
Te Anau	13.17	56.53	2575	36.94
Tokanui	25.99	1.18	567	20.87
Underwood	17.26	2.36	602	30.68
Waikaka	7.54	0.09	252	33.03
Waikiwi	57.13	28.12	3479	40.81

Zone Substation	Line Length (km)	Cable Length (km)	Customers	Customer density
Winton	50.14	1	2525	49.37
Unallocated	1.40	0.83	51	
			Average	**36.29/km**

Customer Connection Assets

TPCL has 36,436 customer connections - for which revenue is earned for providing a connection to the network via the 18 retailers which convey electricity over the network. All of the "other assets" convey energy to these customer connections and essentially are a cost to TPCL that has to be matched by the revenue derived from the customer connections. These customer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large customers. The number and changes over the year are shown in Table 16.

Table 16: Classes of Customer Connections

	Small (≤ 20kVA)				Medium (21 – 99kVA)				Large (≥100kVA)			
Month	1kVA 1ph	8kVA 1ph	10% Fixed Option	20kVA 1ph	15kVA 3ph	30kVA 3ph	50kVA 3ph	75kVA 3ph	100 kVA 3ph	Non ½hr Metered Individual	½hr Metered Individual	Total
Apr-19	173	1,778	9,573	19,052	454	2,943	1,554	244	58	71	203	36,103
May-19	173	1,781	9,641	19,014	454	2,938	1,557	243	57	71	204	36,133
Jun-19	173	1,785	9,833	18,836	457	2,938	1,554	244	56	71	204	36,151
Jul-19	173	1,791	9,870	18,854	457	2,933	1,552	245	60	71	205	36,211
Aug-19	173	1,790	10,128	18,637	462	2,929	1,552	244	60	71	205	36,251
Sep-19	173	1,801	10,103	18,675	462	2,927	1,551	245	60	71	205	36,273
Oct-19	173	1,802	10,081	18,714	463	2,927	1,554	245	60	71	205	36,295
Nov-19	174	1,805	10,288	18,541	463	2,932	1,556	245	60	71	206	36,341
Dec-19	174	1,806	10,339	18,550	463	2,930	1,557	248	59	71	206	36,403
Jan-20	174	1,810	10,338	18,539	463	2,925	1,557	248	60	71	206	36,391
Feb-20	174	1,814	10,343	18,537	464	2,920	1,558	248	60	71	206	36,395
Mar-20	174	1,821	10,363	18,551	466	2,918	1,558	249	59	71	206	36,436

In most cases the fuse forms the demarcation point between TPCL's network and the customer's assets (the "service main") and this is usually located at or near the physical boundary of the customer's property.

TPCL has a range of other assets to provide control or other auxiliary functions as described in Table 17.

Table 17: TPCL's Other Assets

Load Control Assets	
Ripple Injection Plant and Receivers	TPCL currently owns and operates four main 33kV 216⅔Hz 125kVA ripple injection plants at Invercargill, North Makarewa, Gore and Edendale. There is a "backup" 66kV 216⅔Hz 125kVA outdoor ripple injection plant at Winton but this is not operational. At Invercargill, EIL has the same size ripple plant as TPCL and each can act as a backup for the other. Ripple relays at customer's premises respond to the injected ripple signal and switch controllable load (such as hot water cylinders and night-store heaters) providing effective load control for the network.
Protection and Control	
Circuit Breakers	Circuit breakers provide switching and isolation points on the network and generally work with protection relays, to provide automatic detection, operation and isolation of faults. They are usually charged spring or DC coil operated and able to break full load current as well as interruption of all faults.
Protection Relays	Protection relays have always included over-current and earth-fault functions but more recent equipment also includes voltage, frequency, directional and circuit breaker fail functionality in addition to the basic functions. Other relays or sensors may drive circuit breaker operation. Examples include transformer and tap changer temperature sensors, gas accumulation and surge relays, arc flash fibre and point sensors, explosion vents or oil level sensors.
Fuses	Fuses provide fault current interruption of some faults and may be utilised by manual operation to provide isolation at low loading levels. As fuses are a simple over-current device they do not provide a reliable earth fault operation, or any other protection function.
Switches	Switches provide no protection function but allow simple manual operation to provide control or isolation. Switches may be able to break considerable load (e.g. ring-main unit load break switches) but others such as air break switches may only be suitable for operation under low levels of load. Switches may be motorised to provide remote operation for control/isolation. Links generally require operation when de-energised so provide economic but less convenient switch points.
Batteries and Chargers	Batteries, battery chargers and battery monitors provide the direct current (DC) supply systems for circuit breaker control and protection functions and allow continued operation of plant throughout any power outage.
Voltage Regulating Relays	Voltage Regulating Relays (VRR's) provide automatic control of the 'Tap Change On Load' (TCOL) equipment integral to power transformers and regulate the outgoing voltage to within set limits.
Neutral Earthing Resistors (NERs)	Neutral Earthing Resistors (NERs) installed at zone substations limit earth fault currents on the 11kV network. These significantly reduce the earth potential rise which may appear on and around network equipment when an earth fault occurs. They are being fitted with neutral VTs to improve their protection.
SCADA and Communications	
SCADA Master Station	SCADA (Supervisory Control And Data Acquisition) is used for control and monitoring of zone substations and remote switching devices and for activating load control plant The SCADA master station is owned by PowerNet and provided as a service to TPCL. It is located at PowerNet's System Control centre at the Findlay Road GXP, Invercargill. This system is based on the process industry standard 'iFIX' with a New Zealand developed add-on 'iPOWER' to provide full Power Industry functions.
Communication Media	TPCL currently owns and operates a number of different radio systems. These systems transmit protection, SCADA, load control and voice traffic. Most traffic is between zone substations and field devices, and the SCADA master station at System Control. However, in the case of protection traffic, signals are sent directly between the protection devices - generally zone substation to zone substation, or zone substation to field device.

	The radio system is comprised of • Digital microwave radio links which simultaneously convey multiple types of traffic including protection signals, SCADA, and voice. • UHF radio links which generally convey a single type of traffic, but modern systems may convey multiple types of traffic (although at a lower speed than microwave radio links). These are used for protection signals, SCADA, load control and voice. • Point-to-multipoint UHF channels for SCADA. • VHF land mobile channels for voice.
Remote Terminal Units	TPCL owns RTUs at both zone substations and field substations. The table below gives the RTU at each zone substation. Field substations generally use the circuit breaker protection relay or regulator controller as the RTU.

Zone Substation or communication site	RTU
Athol	SEL 3530 over 9600 baud modem
Awarua	SEL Axion over 9600 baud modem
Bluff	Kingfisher CP-11 over 9600 baud modem
Centre Bush	SEL3530 over microwave
Colyer Road	SEL 3530 over Ethernet
Conical Hill	Kingfisher CP-11 over 9600 baud modem
Dipton	SEL Axion over microwave
Edendale	SEL3530 & Harris D20C over 9600 baud modem
Elbow creek	SEL3505 over microwave
Glenham	Kingfisher CP-11 over 9600 baud modem
Gore Injection Plant	Kingfisher CP-11 over 9600 baud modem
Gorge Road	Kingfisher CP-11 over 9600 baud modem
High Peak	SEL3505 over microwave
Heddon Bush	SEL Axion over 9600baud modem
Hedgehope	SEL 3530 over 9600 baud modem
Hillside	Kingfisher CP-11 over 9600 baud modem
Invercargill Injection Plant	Siemens C68 over 300 baud modem
Isla bank	SEL3530 over 9600 baud modem
Kelso	SEL 3530 over 9600 baud modem
Kennington	SEL 3530 over 9600 baud modem
Lumsden	SEL Axion over microwave
Makarewa	SEL 3530 over 9600 baud modem
Mataura	Kingfisher CP-11 over 9600 baud modem
McNab	SEL Axion over 9600 baud modem
Monowai	Kingfisher CP-11 over 9600 baud modem
Mossburn	Kingfisher CP-11 over microwave
North Gore	Kingfisher CP-11 over 9600 baud modem
North Makarewa	Harris D20M++/SEL3530 over 9600 baud modem
Ohai	SEL 3530 over 9600 baud modem
Orawia	Kingfisher CP-11 over 9600 baud modem
Otatara	Kingfisher CP-11 over 9600 baud modem
Otautau	Kingfisher CP-11 over 9600 baud modem
Ramparts	Kingfisher LP1 over 9600 baud modem
Riversdale	Kingfisher CP-11 over 9600 baud modem
Riverton	SEL3530 & Kingfisher CP-11 over 9600 baud modem
Seaward Bush	Harris D20ME over 9600 baud modem
South Gore	SEL 3530 over 9600 baud modem
Te Anau	Kingfisher CP-11 over 9600 baud modem
Tokanui	Kingfisher CP-11 over 9600 baud modem
Twinlaw	Kingfisher PC-1 over 9600 baud modem
Underwood	Kingfisher CP-11 over 9600 baud modem
Waikaka	SEL Axion over 9600 baud modem
Waikiwi	SEL3530 over 9600 baud modem

White Hill	Kingfisher CP-11 over microwave
Winton	SEL3530 over microwave
Winton Hill	SEL 3505 over microwave
Winton Injection Plant	Siemens C68 over 300 baud modem decommissioned

Other Assets	
Generation	TPCL do not own any mobile generation plant but may utilise three diesel generators owned by PowerNet. These are rated at 500kVA, 275kVA and 100kVA. There are two additional 100kVA generators but these would most likely be used by or remain reserved for use on other networks. There are no permanently installed stand-by generators owned or able to be utilised by TPCL.
Power Factor Correction	TPCL owns and operates two 2.5MVAr 66kV capacitors at Heddon Bush and four 5MVA 66kV capacitors at North Makarewa. These were installed during the construction of Meridian Energy Limited's White Hill wind farm to cover the VAR requirements of the generators. Other than the above, customers are required to draw load from connection points with sufficiently good power factor so as to avoid the need for network scale power factor correction.
Mobile equipment	TPCL can utilise a TPCL owned trailer mounted 3MVA 11kV regulator and circuit breaker with cable connections. TPCL can utilise a TPCL owned 66-33/22-11kV 5MVA heavy trailer mounted mobile substation with HV and MV circuit breaker with HV overhead line connection and MV cable connection.
Metering	Most zone substations have time-of-use (TOU) meters on the incomers that provide details of energy flows and power factor.

2.3. Network Asset Details

Bulk Supply Assets and Embedded Generation

TPCL owns the following assets within the GXPs.

Asset	Location	Quantity	Manufactured	Condition
66kV Circuit Breaker	North Makarewa	5	2007 (RL = 27yrs)	Good
66kV Circuit Breaker	North Makarewa	4	2000 (RL = 20yrs)	Good
33kV Circuit Breaker	North Makarewa	1	1973 (RL = -7yrs)	Average
33kV Circuit Breaker	North Makarewa	1	1986 (RL = 6yrs)	Average
33kV Circuit Breaker	North Makarewa	2	1983 (RL = 3yrs)	Average
33kV Circuit Breaker	North Makarewa	2	1984 (RL = 4yrs)	Average
33kV Circuit Breaker	Edendale	7	2002 (RL = 27yrs)	Good
33kV Circuit Breaker	Edendale	1	2015 (RL = 40yrs)	Good
11kV Circuit Breaker	Edendale	5	1994 (RL = 19yrs)	Good
11kV Circuit Breaker	Edendale	1	1995 (RL = 20yrs)	Good
11kV Circuit Breaker	Edendale	1	1996 (RL = 21yrs)	Good
11kV Circuit Breaker	Edendale	1	1998 (RL = 23yrs)	Good
11kV Circuit Breaker	Edendale	2	1999 (RL = 24yrs)	Good
66kV Bus	North Makarewa	1	2000 (RL = 25yrs)	Good
33kV Bus	Edendale	1	2002 (RL = 27yrs)	Good, Indoor switchboard
66kV Capacitor	North Makarewa	4	2006 (RL = 26yrs)	Good
66kV NER	North Makarewa	1	2000 (RL = 26yrs)	Good

Injection Plants

Voltage	Location	Quantity	Manufactured	Condition
66kV	Winton	1	1992 (RL = -6yrs)	Average, coupling cell and capacitors are outdoor. Not in operation.
33kV	Invercargill 1	1	1988 (RL = -10yrs)	Good, all gear is indoor
33kV	Gore	1	1990 (RL = -8yrs)	Good, although it requires an interface upgrade between new controller and Invercargill plant. All gear is indoor
33kV	Edendale	1	1988 (RL = -10yrs)	Good, all gear is indoor
33kV	North Makarewa	1	1994 (RL = -4yrs)	Good, all gear is indoor

All 33kV plants are enclosed within buildings providing protection from the elements and therefore there is an expected greater extended life for the non-electronic components. The electronic components continue to provide good service with the power supply units upgraded in 2005 after failures at other sites. The control equipment at Gore have been replaced in the 2019/20 financial year. The interface plant between Gore and Invercargill injection plants require an upgrade. These plants are expected to be made redundant with the roll out of smart meters and street light controls in the medium term.

There are a number of significant embedded generation plants (i.e. About 1MW or greater) but these are not owned by the company.

Subtransmission Network

Figure 9 below summarises the subtransmission lines constructed each year:

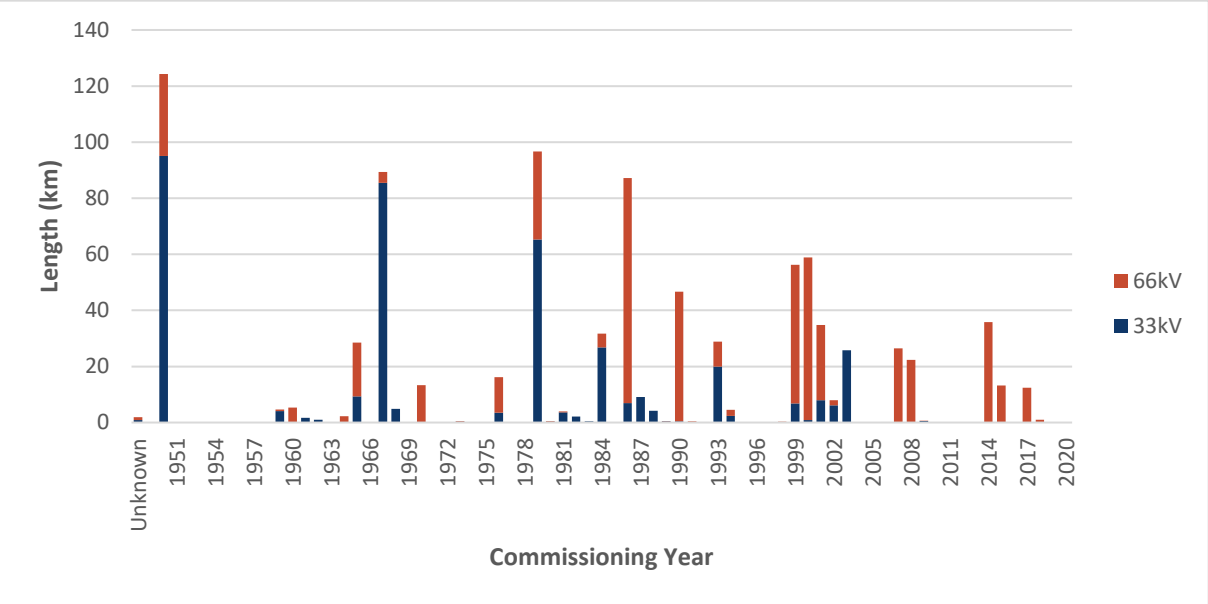


Figure 9: Subtransmission line construction

The Monowai to Redcliff 66kV line is over 60 years old but is still in operational condition. Determining the remaining life for multi-component assets is difficult especially as sections are constructed to differing standards and materials.

Figure 10 shows the ages of poles on the subtransmission network.

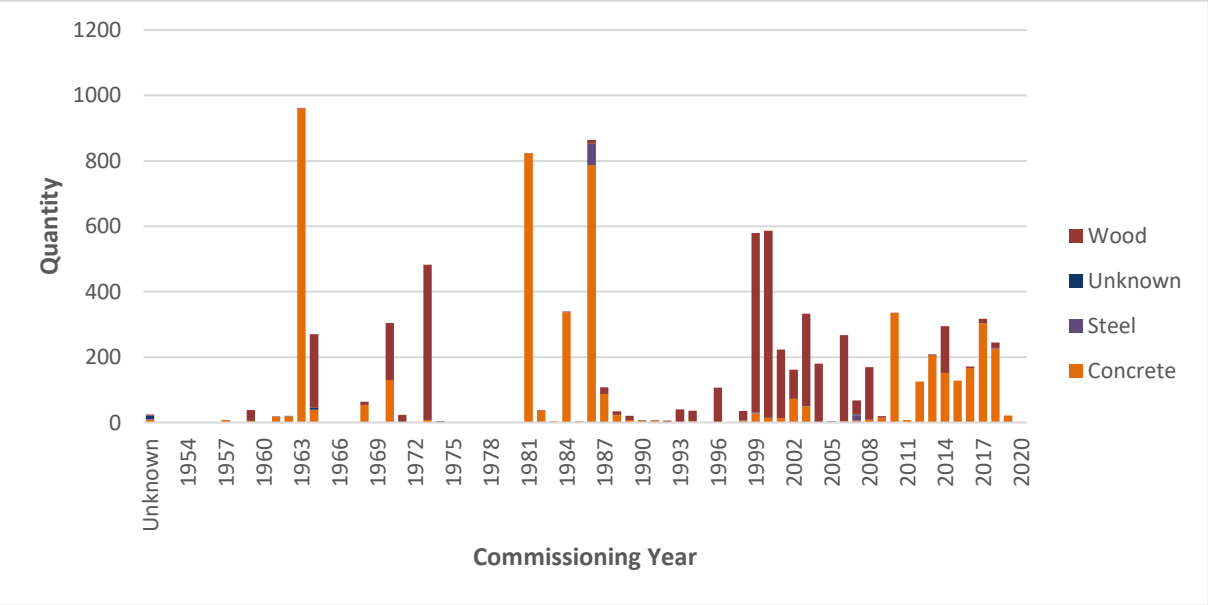


Figure 10: Subtransmission Poles

In theory, based on ODV handbook standard lives for wooden poles, all lines built prior to 1985 should be replaced before the end of 2030. Similarly, for concrete poles, all lines built prior to 1970 should be replaced before the end of 2030. It is noted however, that many poles will exceed the standard lives given above. Pole replacements are based on condition and condition of subtransmission lines is assessed by annual aerial and five-yearly walking condition inspections. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

Subtransmission Cables

In general subtransmission cables are short lengths around zone substations or sections through urban areas where the operative District Plan required cables to be installed underground. The 33kV cables are relatively recent additions to the network and these are in good condition. Earlier XLPE cables (pre-1985) are understood to have a slightly shorter life expectancy however the oldest of these cables is still expected to have a remaining life beyond the 10 year planning horizon.

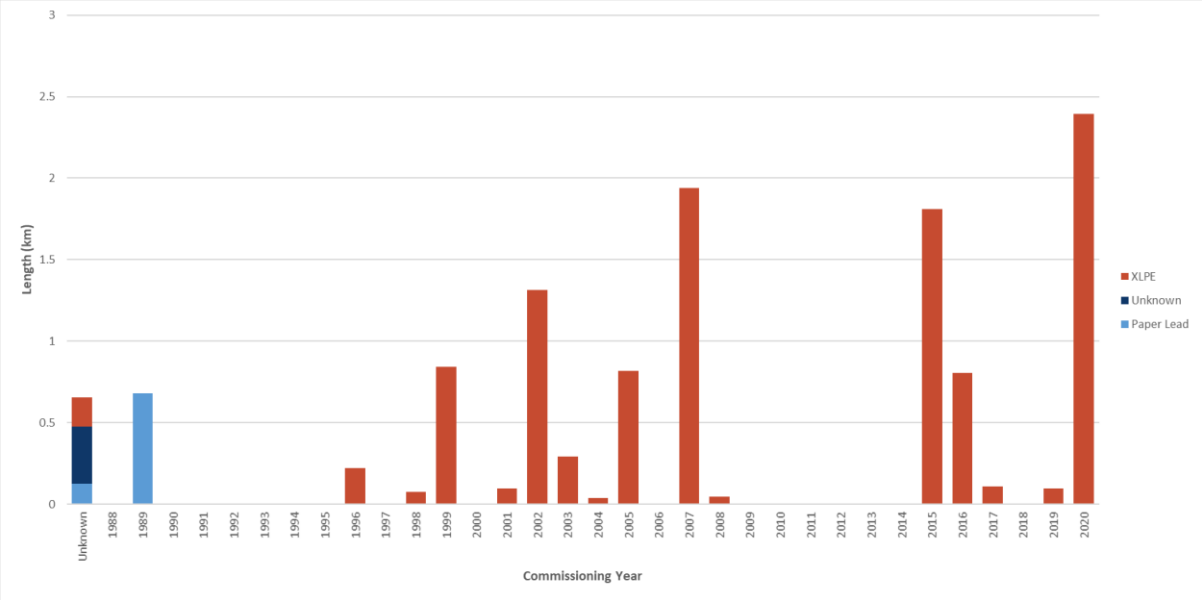


Figure 11: Subtransmission Cables

Zone Substations

Subtransmission Voltage Switchgear

TPCL has three indoor 33kV switchboards at Waikiwi, Edendale and Colyer Road. All other 33kV circuit breakers are outdoor units. All 66kV circuit breakers are installed outdoors and all units installed after 1992 are SF6 insulated. The single remaining oil 66kV circuit breaker, located at Otautau, is in good condition and is not expected to be decommissioned during the 10 year planning period. Six 33kV oil circuit breakers, excluding the North Makarewa circuit breakers, will or have reached their standard lives during the 10 year planning. Renewals of these will be planned when condition inspections determine that they are no longer fit for service.

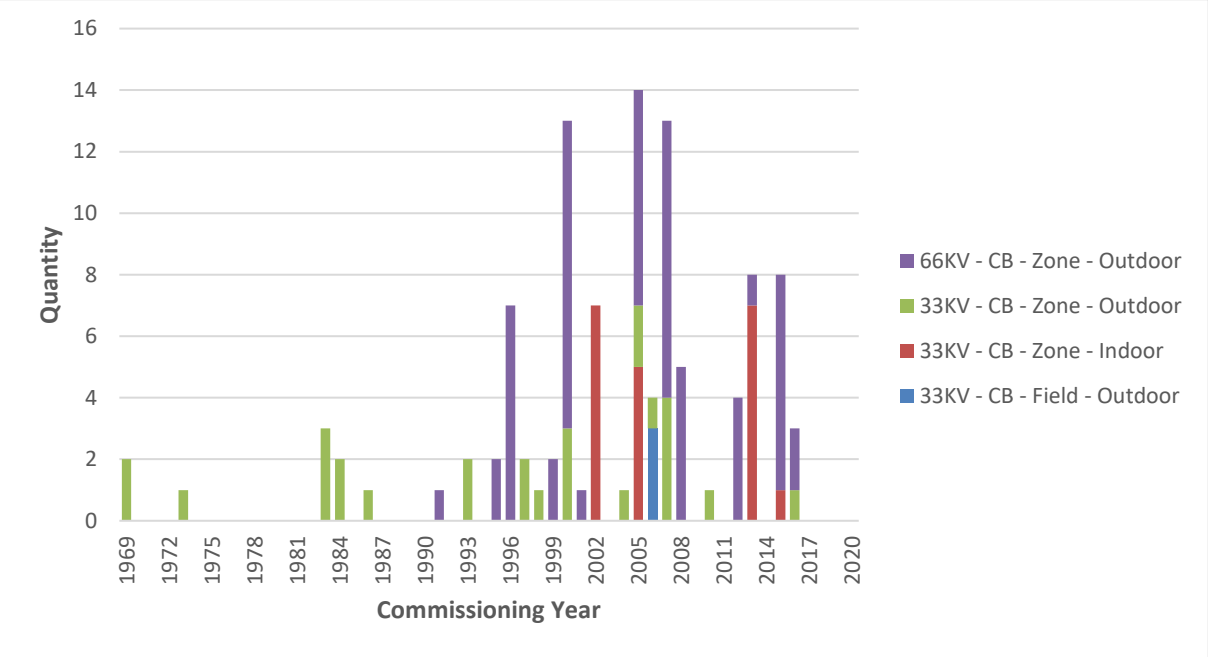


Figure 12: Subtransmission Voltage Circuit Breakers

Power Transformers

The Power Transformers on the network are generally in good condition. Twenty one units are expected to exceed the standard service life of 55 years within the 10 year planning period. This standard service life is longer than the theoretical value in the ODV handbook. Condition of these units will continue to be monitored with many of the older units providing satisfactory service.

Transformers are regularly inspected and oil samples taken periodically over a 12 month cycle. Oil results are captured within the asset management program and units with identified risks are referred for additional analysis. . Identified transformers at Mataura, Seaward Bush, hillside, Conical Hill, Kelso, North Gore, Riversdale, Otatara and George substations are being monitored. The Awarua and Underwood transformers are in need of refurbishment. The first underwood wood transformer will be replaced in 2021 followed by the second unit the following year.

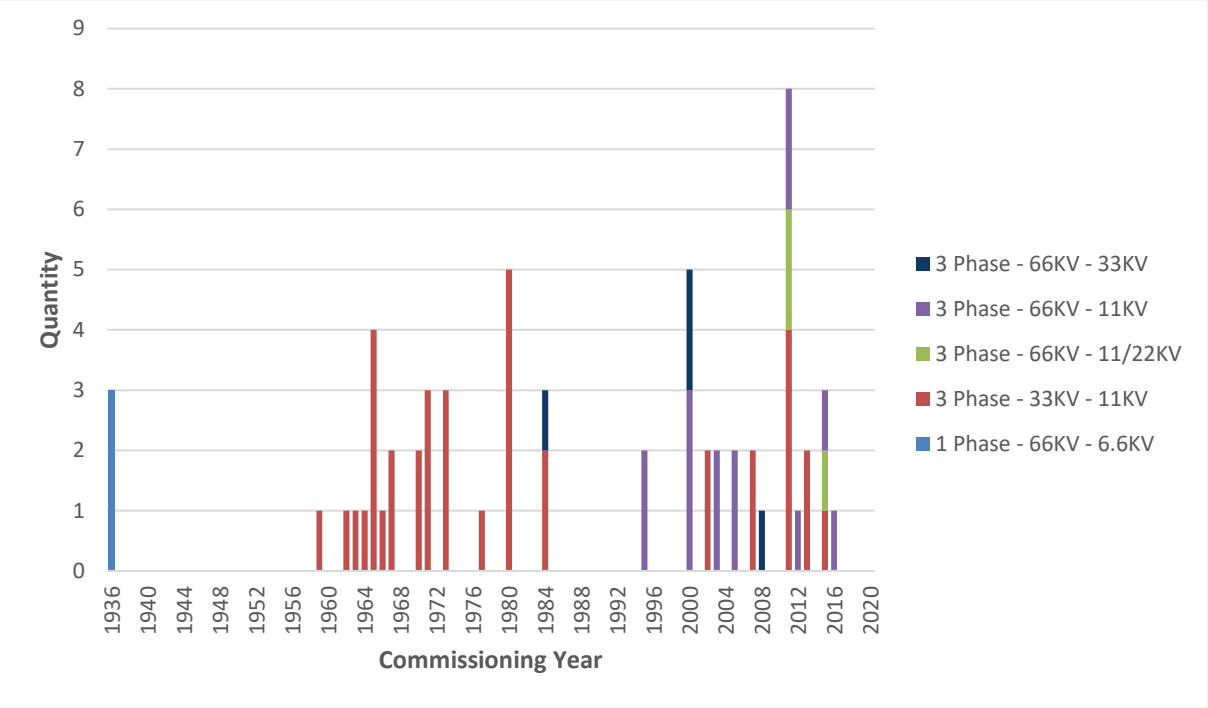


Figure 13: Power Transformers

DC Power Supplies

As DC batteries are essential to the safe operation of protection devices, regular checks are carried out and each battery is replaced prior to the manufacturer's recommended life. No batteries are more than fifteen years old with the majority of battery units below 10 years.

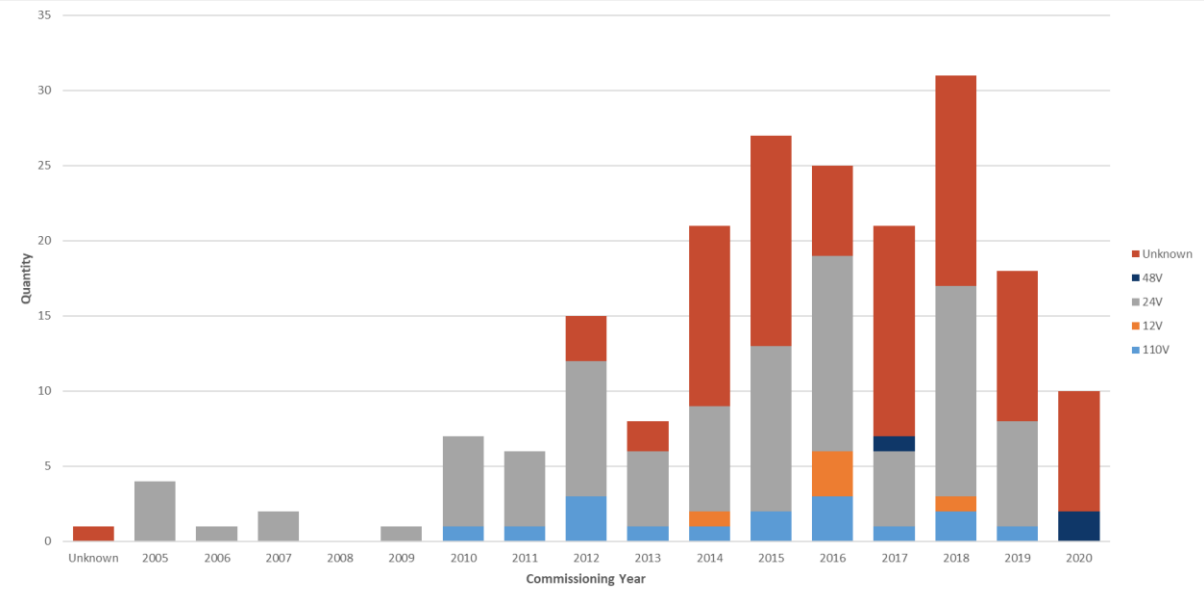


Figure 14: DC Batteries

Tap Changer Controls

116 voltage regulating relays (VRR) are in operation and most have been installed with the associated transformer or voltage regulator. The condition of these is generally good with some recent problems. A number of substation sites utilize single phase voltage regulators, which have a VRR per phase. The two oldest VRRs on the network are at Awarua and Riversdale. The VRR at Riversdale is planned to be

replaced within the next 10 years and the VRR at Awarua is on the T2 transformer which is currently energised but not on load following transfer of load.

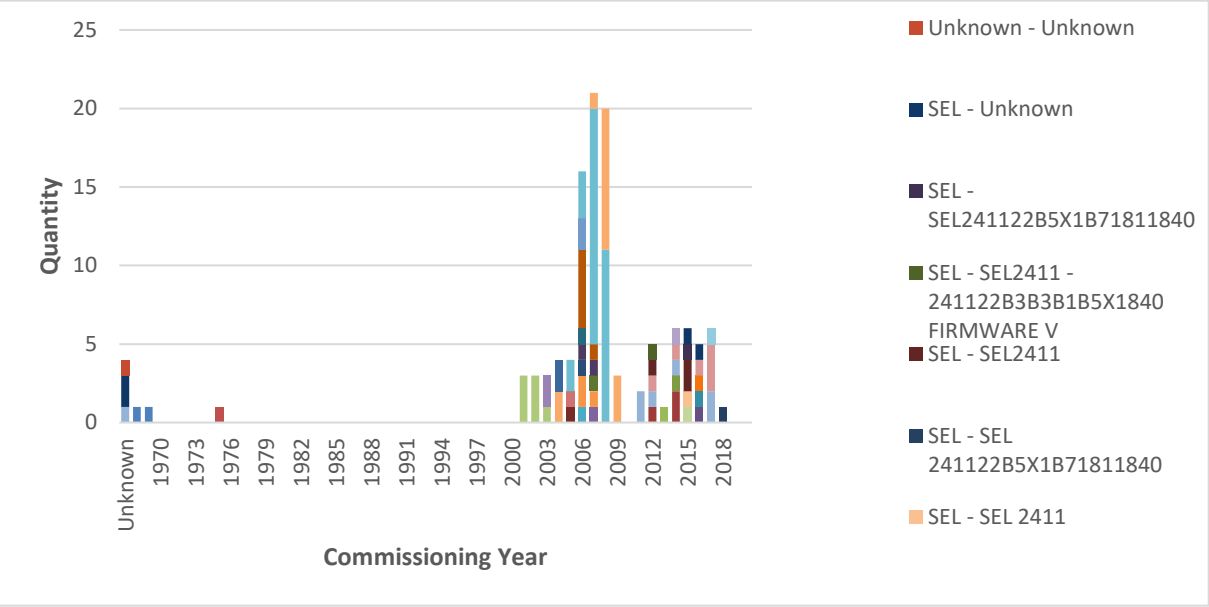


Figure 15: Voltage Regulating Relays

Distribution Network

Circuit Breakers

TPCL has a mix of outdoor and indoor distribution circuit breakers. Older circuit breakers are 11kV to match the operating voltage of the network. 22kV circuit breakers have been installed as part of new substation construction as it provides for future voltage conversion and aligns with a long term plan to convert to 22kV within the lifetime of the equipment.

Indoor circuit breakers have an extra five years standard life over outdoor units, therefore outdoor units installed before 1990, and indoor installed before 1985, should be refurbished or replaced by 2030. 14 indoor circuit breakers, and 11 outdoor, will be due for replacement before 2028. The Bluff and Makarewa indoor switchboards are planned for replacement at the end of their standard life, with the project implementation starting in the 2024/25 financial year.

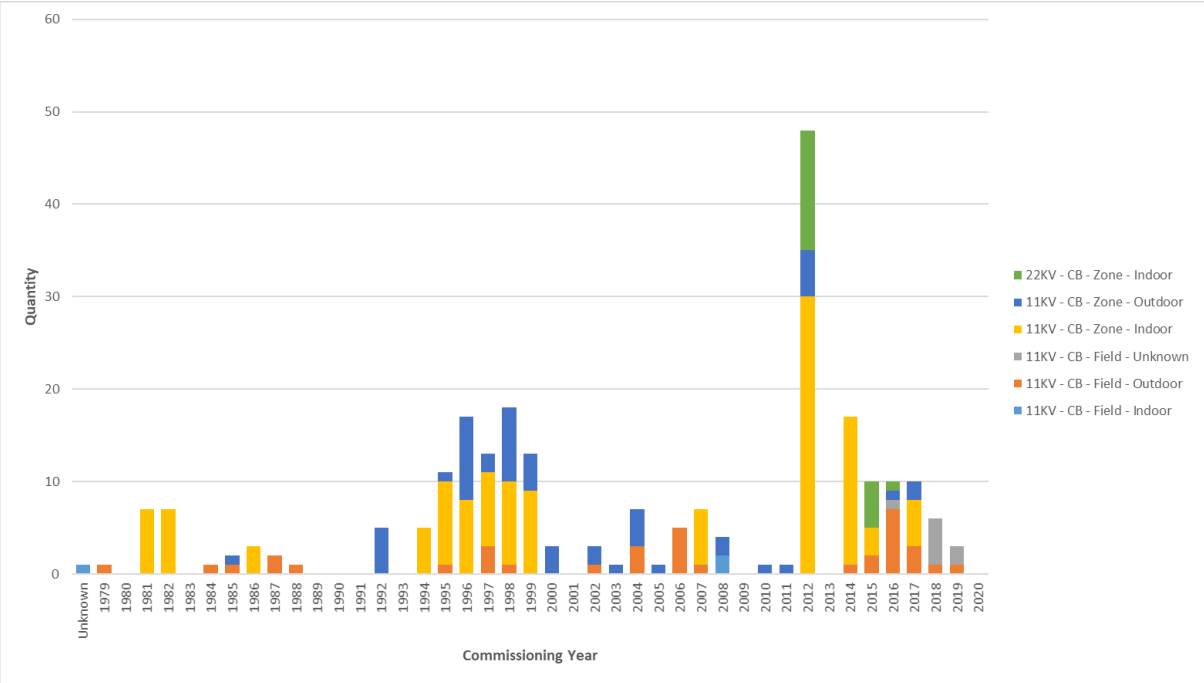


Figure 16: Distribution Circuit Breakers

Air Break Switches

The air break switchgear has the following age profile. The condition of these is generally fair with a proportion of older units.

11kV ABS units installed between 1998 and 2014, have a potential failure risk to any seismic activity resulting into the breaking of the porcelain bushings. The risk pose a safety threat to operators and staff and a works program have been implemented to replace all defective units. The program started during the financial year 2019/20 and will continue until 2029/30.

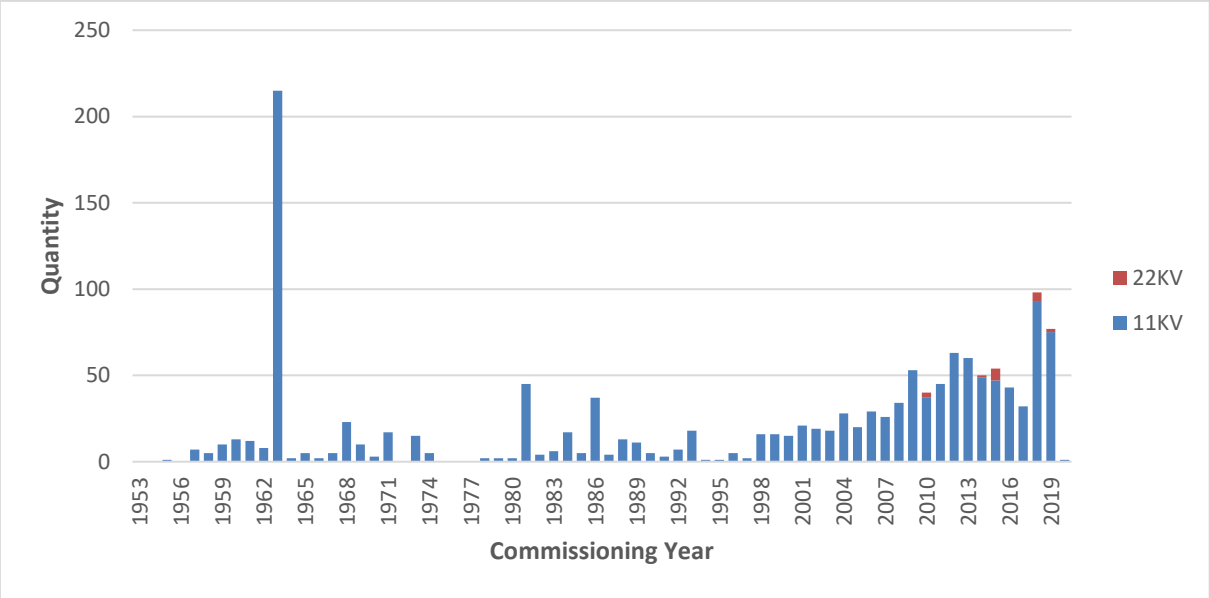


Figure 17: Air Break Switches

Fuses

There are 10,000+ drop-out fuses on the network protecting transformers and laterals. A limited age profile exists for newer units but the vast majority have no known installation date. These have a relatively low failure rate.

Ring Main Units

Ring Main Units (RMU) have the following age profile. As these are relatively recent additions, only the oldest 3 RMUs will be at the end of their standard life in the final few years of the 10-year planning period. Condition inspections will determine requirements for replacement but in general condition is good.

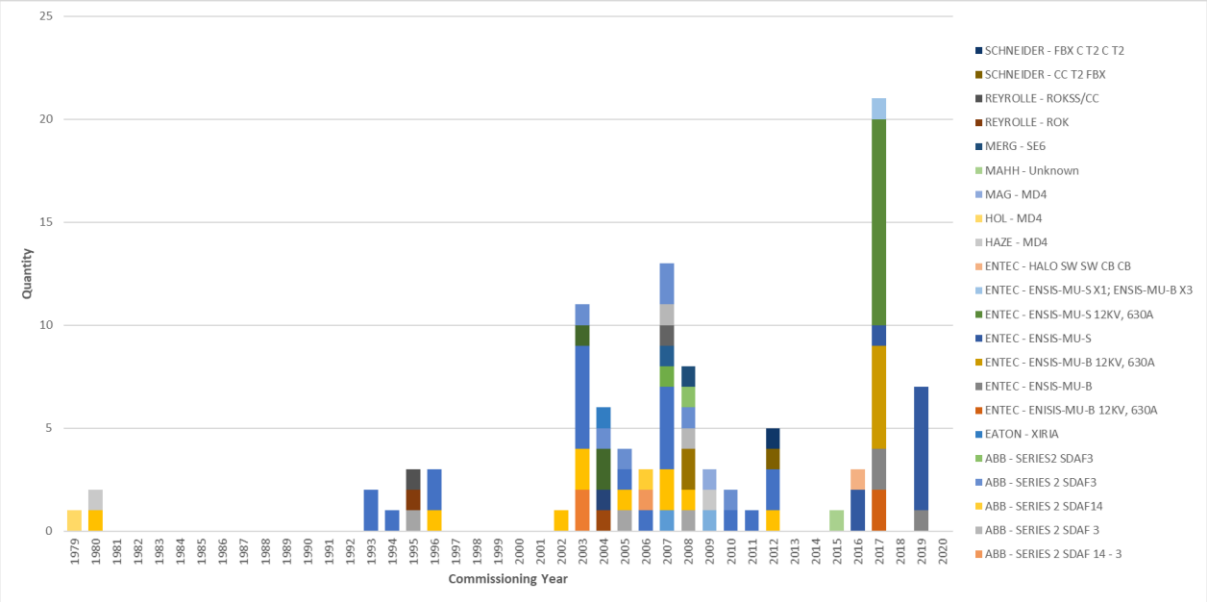


Figure 18: Ring Main Units

Overhead Lines

Distribution network poles have an age profile as shown in Figure 19.

In theory, based on ODV handbook standard lives for wooden poles, all lines built prior to 1986 should be replaced before the end of 2031. Similarly, for concrete poles, all lines built prior to 1971 should be replaced before the end of 2031. It is noted however, that many poles will exceed the standard lives given above. Pole replacements are based on condition and condition of distribution lines is assessed five-yearly walking condition inspections. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

Given the age profile of distribution poles (based on large builds over a few years in the early 1960s) expenditure on pole replacements has increased over the last few years and is expected to stay at this level throughout the planning period. The actual replacement rate will depend on available resources, the amount of new connections requiring upgrades, the five yearly inspection, NDT (Non-Destructive Testing) and fault incidences.

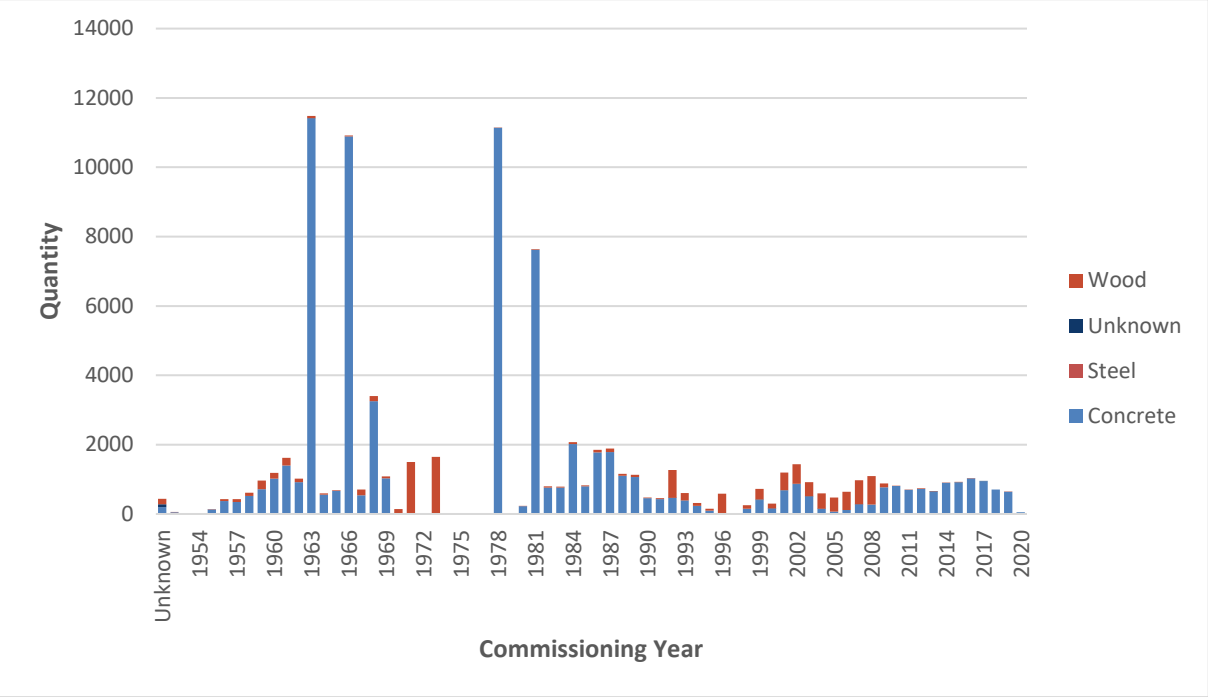


Figure 19: Distribution Poles

Underground Cables

Figure 20 below displays the age of the Distribution cables on the network. The age profile of 11kV cables shows that some XLPE cables may need renewal within the planning period (XLPE cables installed before 1985). These will be monitored and replacement done if failures are predicted. Actual practical life for any cable is likely to be greater than the ODV standard life and on-going monitoring of actual performance will be utilised in planning. Most cables are lightly loaded and in sound condition however there have been termination and joint failures.

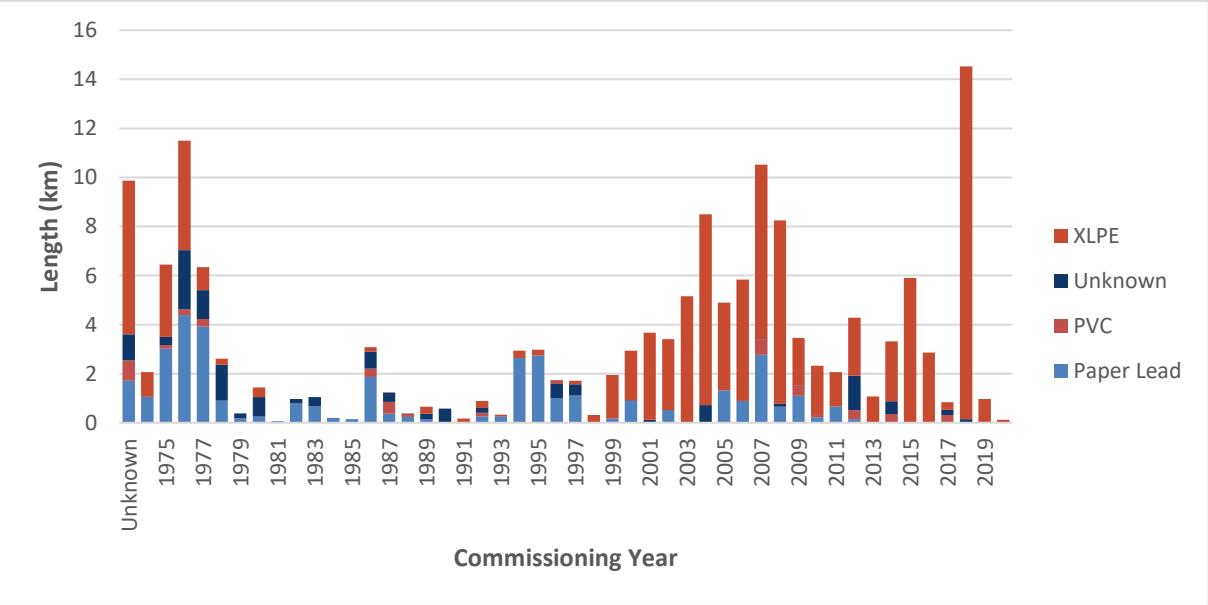


Figure 20: Distribution Cables

Voltage Regulators

The age profile for voltage regulators is shown in Figure 21. Voltage regulators exist on TPCL's network for voltage improvement and to allow for 11kV backups between zone substations. All units are modern single phase units with the oldest units installed in 2001.

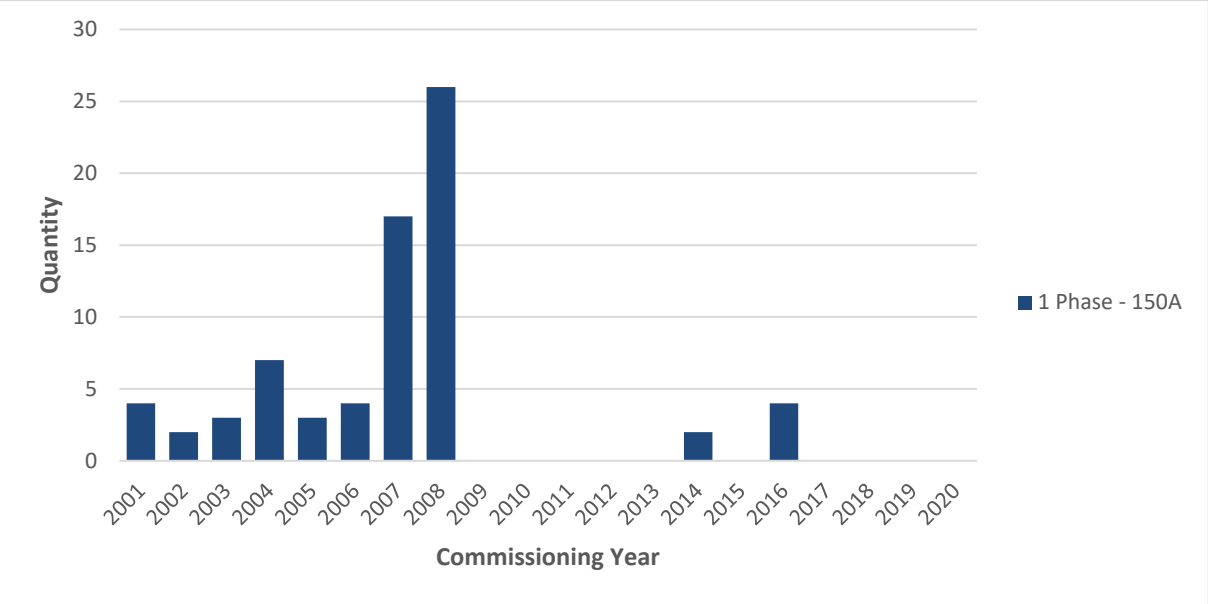


Figure 21: Voltage Regulators

Distribution Substations

Transformers

Table 18 shows the numbers of the various sized distribution transformers on TPCL's network and their age profile is displayed in Figure 22. Two spikes occur at 1970 and 1986 where estimated ages have been used, as the actual manufacturing year was not able to be found.

Most of TPCL's transformers are pole mounted with a much smaller number of ground mounted transformers – generally in larger urban townships or at individual larger customer's premises.

Table 18: Distribution Transformers

Rating	Pole	Ground
1-phase up to 15kVA	4756	29
1-phase 30kVA	430	11
1-phase 50kVA	13	1
3-phase up to 15kVA	1962	3
3-phase 30kVA	1787	44
3-phase 50kVA	981	43
3-phase 75kVA	284	13
3-phase 100kVA	203	82
3-phase 200kVA	108	214
3-phase 300kVA	48	110
3-phase 500kVA	3	44
3-phase 750kVA	3	22
3-phase 1,000kVA	1	11
3-phase 1,500kVA		12
Total	**10579**	**639**

Transformers found to be in poor condition after five yearly inspections will be replaced, some replaced units may be refurbished units. Condition varies generally due to proximity to the coast and if the unit has been heavily loaded.

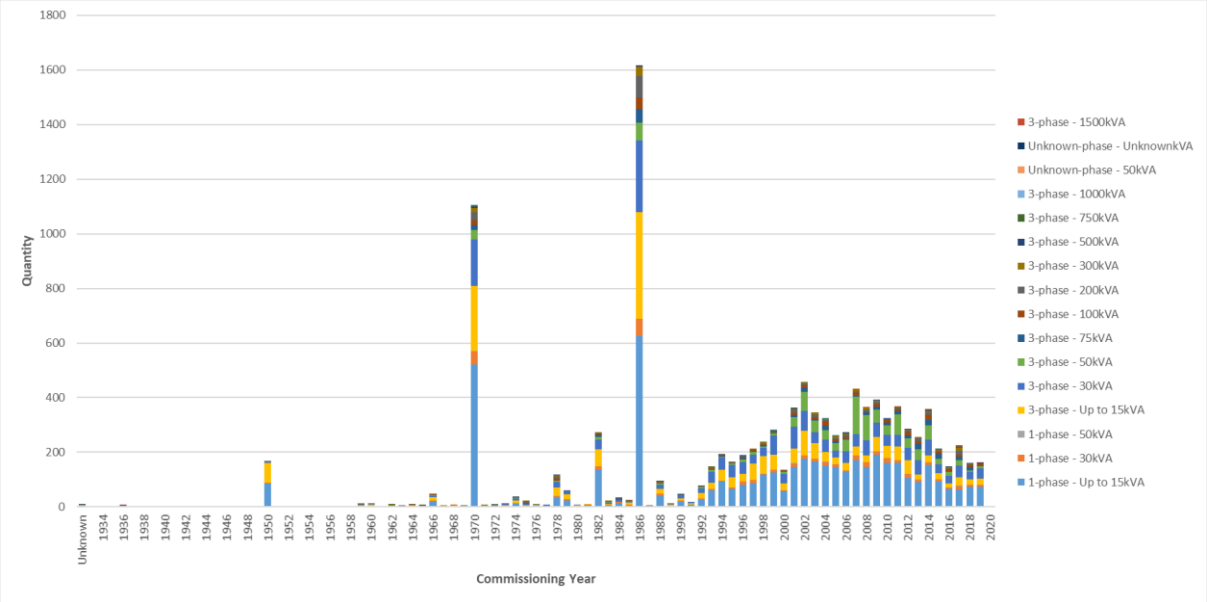


Figure 22: Distribution Transformers

Remote Terminal Units

Age profile of Remote Terminal Units (RTU) is shown in Figure 23. A number of units are exceeding the standard age of 15 years and condition is average. The older Siemens units starting to become difficult to maintain and are planned to be replaced in future year. The Harris RTUs are becoming harder to maintain due to difficulties in finding personnel who can reprogram these units when changes are required. In some cases a new SEL 3530 or SEL Axion RTU connected to new equipment is installed in parallel with the existing Harris RTU, which remains connected to older equipment. Over the next 5 years the older equipment will be migrated to the SEL 3530 or SEL Axion RTU's. .

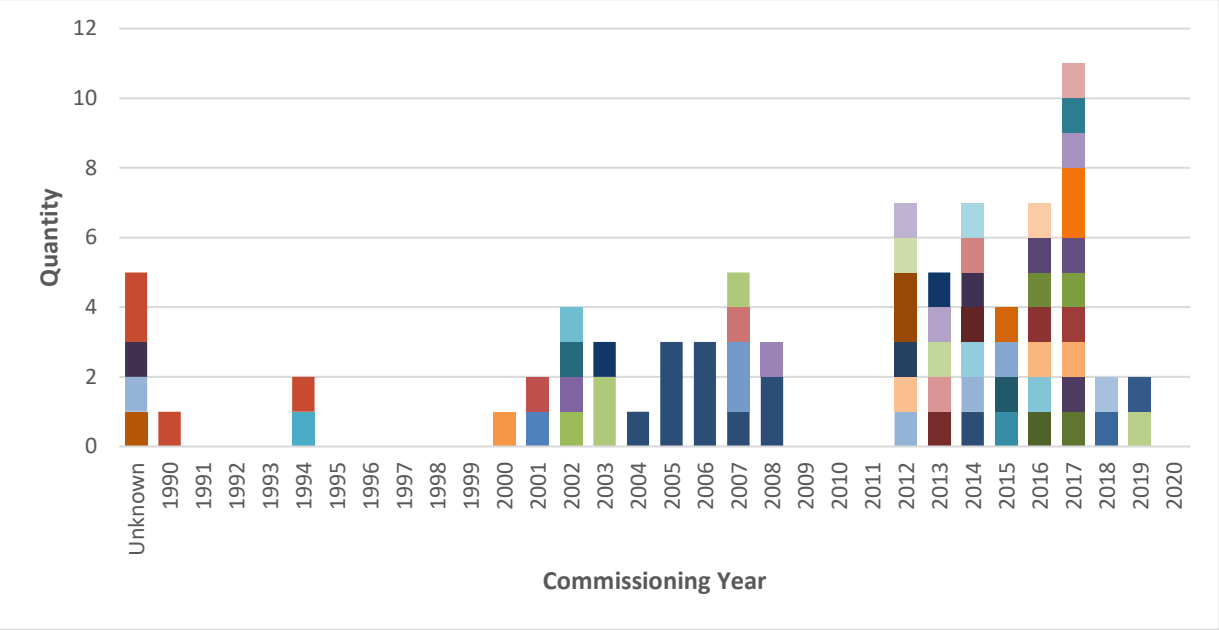


Figure 23: Remote Terminal Unit Assets

LV Network

Overhead

The age profile of the 400 volt poles is shown in Figure 24. Conditions of these are average, with a large number of poles due for renewal this planning period based on age. Five-yearly walking condition inspections are made of all LV lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

New overhead line is being installed as ABC (Aerial Bundled Conductor) which does not require cross arms and insulators and has PVC insulation improving line safety.

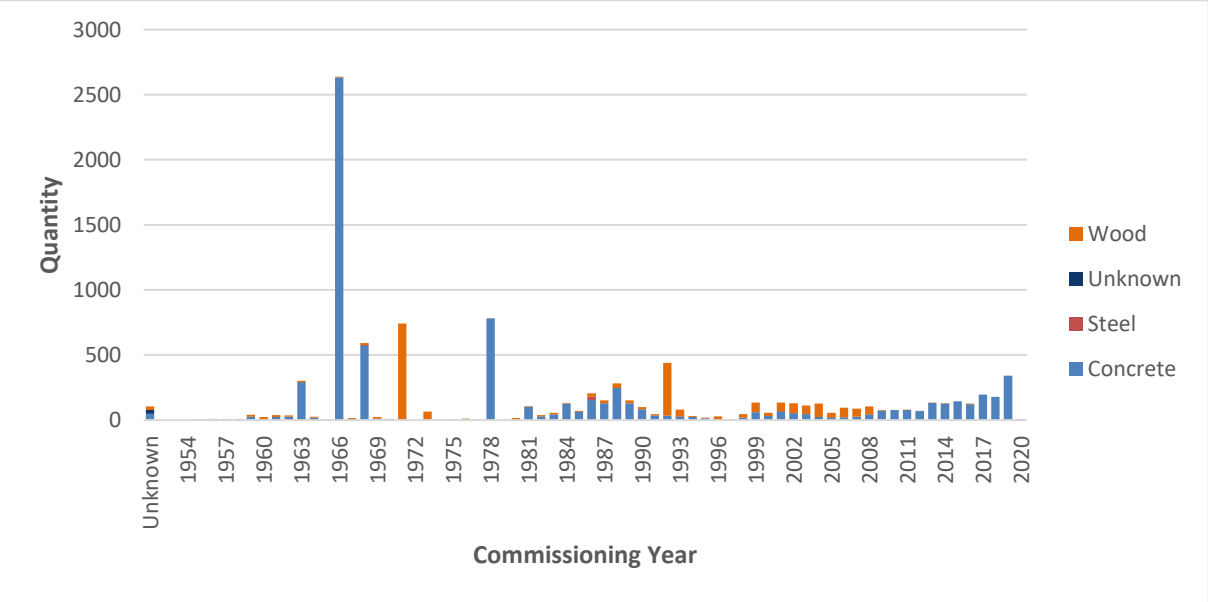


Figure 24: LV Lines

Underground

The LV cable commissioning year profile is shown in Figure 25 and highlights that based on age, a number of assets should be renewed. In practice cables are left in service until performance deteriorates impacting on service levels.

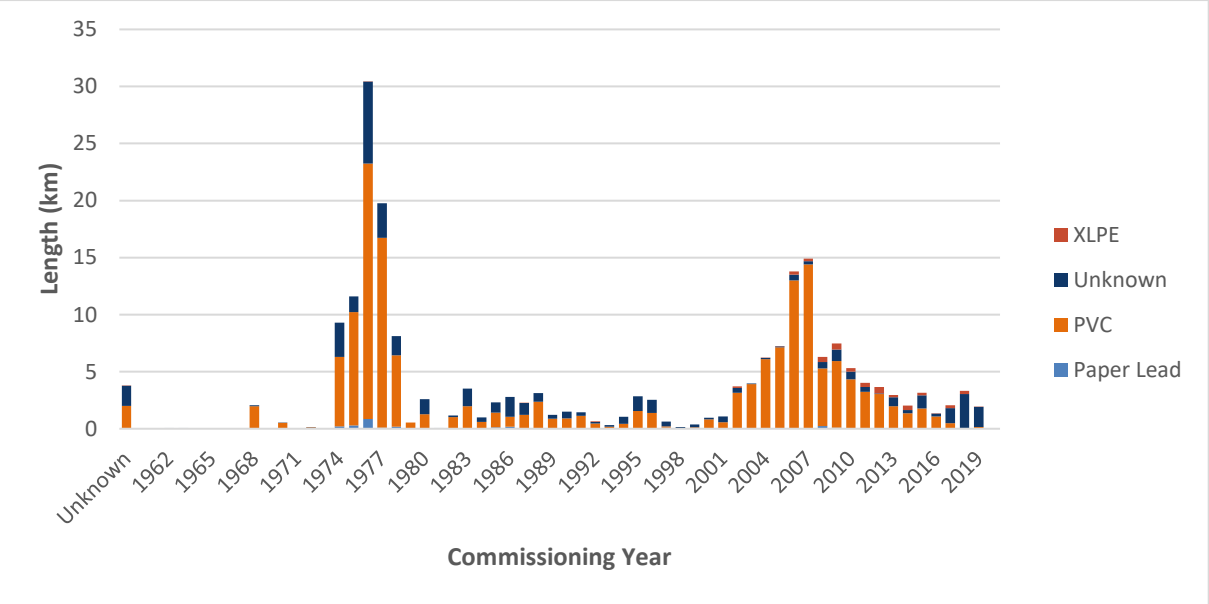


Figure 25: LV Cables

Other Assets

SCADA and Communications

The initial SCADA master station was commissioned in 1999 with a further upgrade of the Server PC's in 2005 and most recently in 2017. The software has been developed with the latest version being implemented with the new servers in 2017. A disaster recovery station has been installed in a nearby Transpower substation.

The age profile of radios used for communications is given in Figure 26. Manufacture support has ended for many of MAS DXR1500 microwaves and the remaining two will be renewed over the next three years. Manufacturer support has ended for the Exicom EX7100 due to the business being liquidated. TPCL has a spare unit but due to the criticality of the protection links operating on these radios, they will be replaced as required over the next few years to ensure a spare is always available. A consulting firm is working on a report which will provide advice on the wider development and asset management of the communications system.

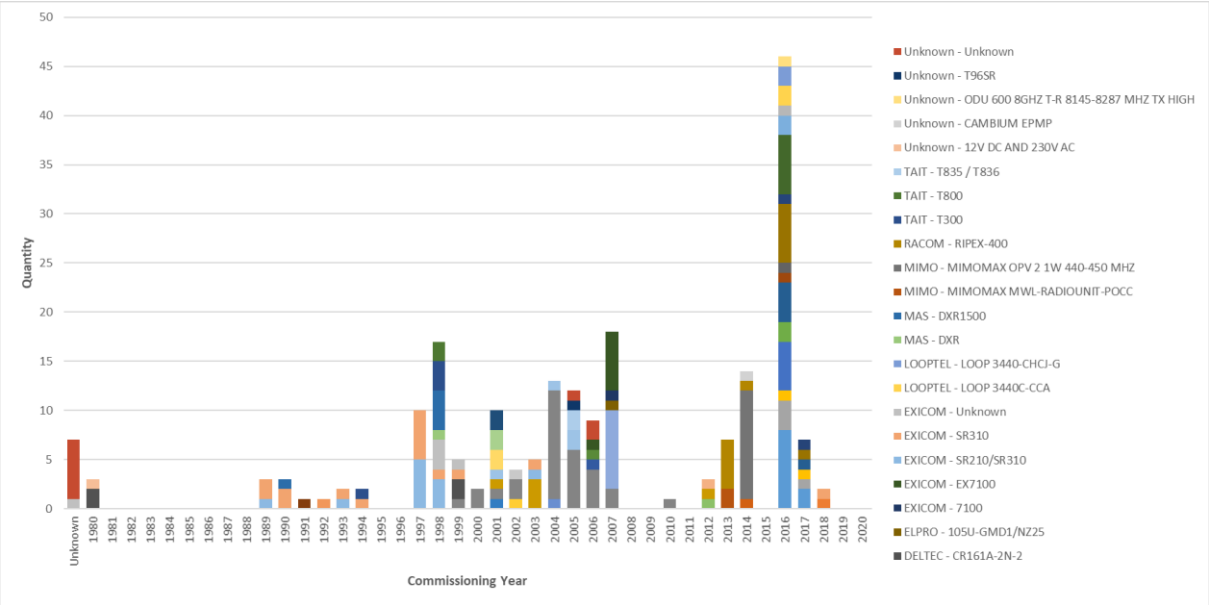


Figure 26: Radios

Metering

TPCL has 'Time Of Use' (TOU) meters on its incoming circuit breakers to provide accurate loading information on each zone substation. There are also TOU meters on some feeders to provide indicative load profiles for certain load groups. The age profile of these is shown in Figure 27.

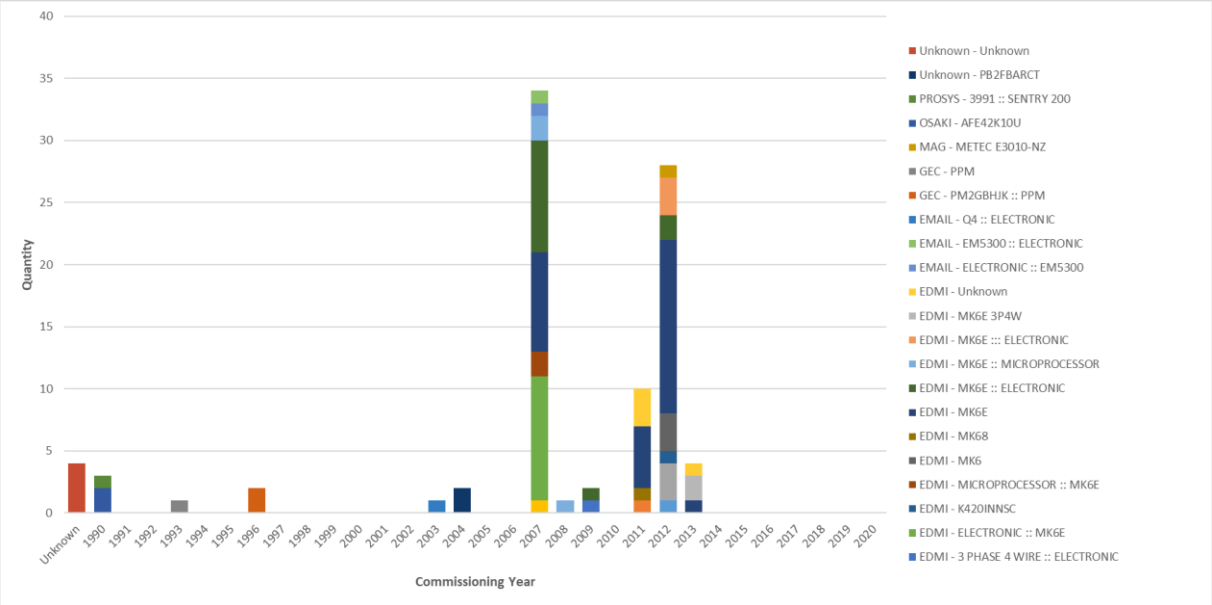


Figure 27: Metering Assets

Mobile Plant/ Load Correction/ Generation

TPCL own one mobile 3MVA 11kV Regulator on a heavy trailer owned separately by Powernet. Condition of this unit is good with the trailer repainted and regulator maintained during 2013. The control system will be replaced in 2021.

TPCL owns a 5MVA 66-33/22-11kV heavy trailer mounted mobile substation with HV and MV circuit breaker with HV overhead line connection and MV cable connection.

TPCL does not own any power factor correction plant, mobile generation or standby generation plant directly however PowerNet owns mobile diesel generators rated at 500kVA, 275kVA and 100kVA which TPCL can utilise. The standby plant is typically used during planned works on the network where no back feed ability exists within the network (laterals or spurs) or during offload operations. The mobile generators are available to all networks and not purely dedicated to TPCL network.

3. Service Levels

This section describes how TPCL set its various service levels according to the safety, viability, quality, compliance and price objectives that are most important to stakeholders (see Drivers and Constraints). It details how well TPCL is meeting these objectives and what trade-offs exist between differing stakeholders. Considerations include; the desire for Return on Investment (ROI) vs desire for low price with good reliability, safety as first priority vs acceptable levels of risk and whether supply restoration should be prioritised ahead of compliance.

A broad range of service levels are created for TPCL's stakeholders, ranging from those paid for (for their own benefit) by connected customers such as capacity, continuity and restoration to those subsidised by connected customers such as ground clearances, earthing, absence of electrical interference, compliance with the District Plan and submitting regulatory disclosures. This section describes those service levels in detail and how TPCL justifies the service levels delivered to its stakeholders.

Safety is a top priority for TPCL and is a primary consideration in the AMP, but it should be noted that safety has always been a prime consideration in network design, which means that the residual risk able to be addressed through asset management planning is extremely low. Operational factors tend to dominate the year-to-year variation in safety incidents and near hits. Therefore safety KPIs are not presented in the Asset Management Plan, but are available to interested parties upon request.

3.1. Customer Oriented Service Levels

Customer engagement surveys are completed annually to measure customer perceptions around a range of service levels. This involves contacting a large sample of customers by phone and asking a predetermined set of questions. This is carried out independently by engaging Research First who collate the results into a customer satisfaction report for presentation.

Statistics around voltage complaints are kept to measure how often voltage quality issues are experienced by customers. Issues are dealt with at the time but these statistics give an indication of how voltage quality and the response services are trending over time.

Targeted improvement initiatives could result from dissatisfaction being expressed by customers; however survey results show that for the most part customers are happy with the current level of service. Customer engagement telephone surveys indicate that customers value continuity and restoration of supply more highly than other attributes such as answering the phone quickly, quick processing of new connection applications etc. It also appears that there is an increasing value by customers placed on the absence of flicker, sags, surges and brown-outs although other research indicates that flicker is probably noticed more often than it is actually a problem.

The difficulty with these conclusions is that the service levels most valued by customers depend strongly on fixed assets to address and hence require capital expenditure solutions (as opposed to process solutions) which raises the following three issues:

- Limited substitutability between service levels e.g. customers prefer TPCL to keep the power on rather than answer the phone quickly.
- Averaging effect i.e. all customers connected to an asset (or chain of assets) will receive about the same level of service.

- Free-rider effect i.e. customers who choose not to pay for improved service levels would still receive improved service due to their common connection[9].

Primary Customer Service Levels

Surveyed customers have indicated that they value continuity and then restoration most highly; therefore TPCL's primary service levels are continuity and restoration. To measure performance in this area TPCL has adopted two internationally accepted indices:

- **SAIFI** (system average interruption frequency index) is a measure of how many system interruptions occur per year per customer connected to the network.
- **SAIDI** (system average interruption duration index) is a measure of how many system minutes of supply are interrupted per year per customer connected to the network.

This aligns with the Commerce Commission's use of SAIFI and SAIDI (and determine their calculation methodology) in their regulation of local EDBs (Electricity Distribution Business) (noting that TPCL is exempt from price-quality regulation due to its consumer ownership). TPCL's projections for these measures over the next ten year period ending 31 March 2031 are shown in

Table 19. These projections take into account the recently updated default price quality path calculation methodology including new (lower) extreme event normalising boundaries and a 50% weighting for planned outages. TPCL's reliability targets are set equivalent to these projections and the Current asset application of no material deterioration in conjunction will keep the reliable performance at neutral. A small improvement due to automated tie switches and targeted condition based feeder maintenance improves unplanned SAIDI projections slightly. An increased focus on capital works from 2025/26 onwards will increase planned outage performance while the subsequent result will improve unplanned outage performance.

Table 19: TPCL Reliability Projections

Measure	Class	2021/22	2022/23	2023/24	2024/25	2025/26	...	2030/31
SAIDI	B (Planned)	131.54	131.54	131.54	131.54	145.72		145.72
	C (Unplanned)	153.40	151.83	150.27	148.70	146.36		134.62
	Total	**269.13**	**268.78**	**268.17**	**267.22**	**285.68**		**260.92**
SAIFI	B (Planned)	0.61	0.61	0.61	0.67	0.61		0.67
	C (Unplanned)	3.42	3.39	3.35	3.31	3.28		3.10
	Total	**4.03**	**3.99**	**3.96**	**3.92**	**3.95**		**3.77**

The historical trend of SAIDI and SAIFI is shown in Table 20 to enable comparison with the projections above.

Table 20: SAIDI and SAIFI historical trend

Measure	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
SAIDI	148.99	142.78	190.67	225.92	139.90	202.5	199.4	255.7
SAIFI	2.38	2.65	2.88	3.39	2.16	2.69	2.73	3.5

[9] This is the case with Invercargill and North Makarewa GXP's as they are more secure, due to the reliability required by the New Zealand Aluminium Smelter at Tiwai point.

In practical terms this means TPCL's customers can broadly expect the reliability shown in Table 21. Large industrial customers will receive reliability in line with the individual supply arrangements they have made, which can range from uninterrupted N-1 supply to single supply off the local 11kV feeder.

Table 21: Expected fault frequency and restoration time

General location	Expected reliability[10]
Parts of Invercargill not supplied by EIL	One outage per year of about 30 minutes duration
Large towns	Two outages per year of about 45 minutes duration
Small towns	Three outages per year of about 60 minutes duration
Village	Four outages per year of about 120 minutes duration
Anywhere else	Five outages per year of about 240 minutes duration

Customers in all market segments surveyed indicated a preference for paying about the same line charges to receive about the same level of supply reliability.

Table 22 shows the theoretical thresholds which would apply to TPCL's reliability performance if it were regulated. The boundary values represent the threshold for normalising extreme events where if SAIDI or SAIFI in any day exceeds the respective boundary the contribution to the overall annual SAIDI or SAIFI is capped at that boundary value. The limit represents the upper limits of acceptable reliability for network performance after normalising out extreme events and must not be breached annually. Planned interruption compliance is assessed over the full 5 year DPP period. It is worth noting that whilst TPCL is not regulated, and none of these calculated values apply to TPCL, TPCL calculates its performance in alignment with these measures in order to allow for benchmarking against other EDBs.

Table 22: TPCL Theoretical Reliability Thresholds

	Target	Cap/Limit	Boundary
SAIDI - UNPLANNED	128.66	156.53	9.403
SAIFI - UNPLANNED	2.966	3.564	0.1581
SAIDI – PLANNED*	47.271	141.814	N/A
SAIFI – PLANNED*	0.221	0.664	N/A
***Planned interruption compliance is assessed for the regulatory period at 5X cap**			

Secondary Customer Service Levels

Secondary service levels are the attributes of service that TPCL customers have ranked below the first and second most important attributes of supply continuity and restoration. The key point to note is that some of these service levels are process driven which has two implications:

- They tend to be cheaper than fixed asset solutions e.g. staff could work a few hours overtime to process a back log of new connection applications and could divert an over-loaded phone, or TPCL could improve the shut-down notification process.
- They can be provided exclusively to customers who are willing to pay more in contrast to fixed asset solutions which will equally benefit all customers connected to an asset regardless of whether they pay.

These attributes include how satisfied customers are with communication regarding tree trimming, connections or faults, the time taken to respond to and remedy justified voltage complaints and the

[10] Except if supplied directly off the faulty substation, or section of line or cable.

amount of notice before planned shutdowns. Table 23 sets out targets for these service levels for the next ten years.

Table 23: Secondary service levels

Attribute	Measure	2021/22	2022/23	…	2030/31
Planned Outages	Provide sufficient information. {CES}	>80%	>80%	…	>80%
	Satisfaction regarding amount of notice. {CES}	>80%	>80%	…	>80%
	Acceptance of maximum of one planned outage per year. {CES}	>50%	>50%	…	>50%
	Acceptance of planned outages lasting four hours on average. {CES}	>50%	>50%	…	>50%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES}	>80%	>80%	…	>80%
	Information supplied was satisfactory. {CES}	>80%	>80%	…	>80%
	PowerNet first choice to contact for faults. {CES}	>40%	>40%	…	>50%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<10	<10	…	<10
	Number of customers who have justified complaints regarding supply quality {IK}	<3	<3	…	<2

{ } indicates information source: CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

Other Service Levels

In addition to the service levels that are of primary and secondary importance to customers and which they pay for, there are a number of service levels that benefit other stakeholders such as safety, amenity value, absence of electrical interference and performance data. Some (in fact most) of these service levels are imposed on TPCL by statute and while they are for the public good, i.e. necessary for the proper functioning of a safe and orderly community, TPCL is expected to absorb the associated costs into its overall cost base.

Table 24: Other Service Levels

Service Level	Description
Safety	Various legal requirements require TPCL's assets (and customer's plant) to adhere to certain safety standards which include earthing exposed metal and maintaining specified line clearances from trees and from the ground: • Health and Safety at Work Act 2015. • Electricity (Safety) Regulations 2010 • Electricity (Hazards from Trees) Regulations 2003. • Maintaining safe clearances from live conductors (NZECP34 or AS2067). • EEA Guide to Power System Earthing Practice 2009 as a means of compliance with the Electricity (Safety) Regulations.
Amenity Value	There are a number of Acts and other requirements that limit where TPCL can adopt overhead lines: • The Resource Management Act 1991. • The operative District Plans. • Relevant parts of the operative Regional Plan. • Land Transport requirements.

Service Level	Description
	• Civil Aviation requirements. • Land Transfer Act 1952 (easements)
Industry Performance	The Commerce Act 1986 empowers the Commerce Commission to require TPCL to compile and disclose prescribed information to specified standards.
Electrical Interference	Under certain operational conditions TPCL's assets can interfere with other utilities such as phone wires and railway signalling or with the correct operation of customer's plant or TPCL's own equipment. The following publications are used to prevent issues from interference: • Harmonic levels (NZECP36:1993). • Single wire earth return limitations (EEA High Voltage SWER Systems Guide). • NZCCPTS: coordination of power and telecommunications (several guides).

3.2. Regulatory Service Levels

Various Acts and Regulations require TPCL to deliver a range of outcomes within specified timeframes, such as the following;

- Ensure customer satisfaction with both pricing and reliability to avoid being placed under a restraining regime.
- Publicly disclose an AMP each year.
- Publicly disclose prescribed performance measures each year.

TPCL is also required to disclose a range of internal performance and efficiency measures as required by the Electricity Distribution Information Disclosure Determination 2012. However previous disclosures were required under Electricity Distribution (Information Disclosure) Requirements 2008 with the complete listing of these measures included in TPCL's disclosure to 31 March 2020 and with listing and analysis also on the Commerce Commission website http://www.comcom.govt.nz/electricity-information-disclosure-summary-and-analysis/.

Financial Efficiency Measures

TPCL financial efficiency measures fall into two groups:

- Network OPEX metrics
- Non-Network OPEX metrics

However for effective benchmarking this OPEX must be measured against the relative size of the EDBs in question. As there is no single fair measure of the "size" of an EDB, TPCL has adopted the most consistent (and therefore predictable) measures from Information Disclosure Schedule 1:

- Installation Control Points (ICPs) as at year end
- Total km network length
- Total MVA of EDB-owned distribution transformer capacity.

TPCL therefore has six financial efficiency targets as shown in Table 25.

Table 25: Financial Efficiency Targets

Measure	Network OPEX			Non-Network OPEX		
	/ICP	/km	/MVA	/ICP	/km	/MVA
2021/22	300	1213	24274	146	591	11812
2022/23	300	1213	24274	146	591	11812
2023/24	300	1213	24274	146	591	11812
2024/25	300	1213	24274	146	591	11812
2025/26	300	1213	24274	146	591	11812
2026/27	300	1213	24274	146	591	11812
2027/28	300	1213	24274	146	591	11812
2028/29	300	1213	24274	146	591	11812
2029/30	300	1213	24274	146	591	11812
2030/31	300	1213	24274	146	591	11812

Comparative benchmarking as discussed in **Benchmarking** shows these service levels to be in line with peers once allowance is made for network size measures, therefore continuation at current levels is justified. Evaluating historical performance levels, along with limitations on funding availability, the financial efficiency targets are set to align with past performance levels.

Energy Delivery Efficiency Measures

Projected energy efficiency forecasts and targets are shown in Table 26. These measures are:

- Load factor – [kWh entering TPCL's network during the year] / [[max demand for the year] x [hours in the year]].
- Loss ratio – [kWh lost in TPCL's network during the year] / [kWh entering TPCL's network during the year].
- Capacity utilisation – [max demand for the year] / [installed transformer capacity].

Slight improvements are targeted but changes in Transmission Pricing Methodology have impacted the load factor. It may take a number of years for the Lower South Island (LSI) peak to settle down to a predictable level.

Loss ratio has varied due to reliance on annual sales quantities from retailers. As retailers are not reading the customers meter at midnight of the 31 December, some estimation methodology is required.

Table 26: Energy Efficiency Targets

Measure	2021/22	2022/23	…	2030/31
Load Factor	65%	65%	…	65%
Loss Ratio	7.0%	7.0%	…	7.0%
Capacity Utilisation	30%	30%	…	31%

3.3. Service Level Justification

TPCL's service levels are justified when:

- Customers have indicated preference for paying the same line charges for the same service levels.
- Improvements provide positive cost benefit within revenue capability.
- Customer contributions fund uneconomic portions of upgrade or alteration expenses to achieve a desired service level for an individual or group of customers.
- Skilled labour and technical shortages constrain what can be achieved.
- External agencies impose service levels either directly or indirectly where an unrelated condition or restriction manifests as a service level e.g. a requirement to place all new lines underground or a requirement to increase clearances.
- Customer expectations of service levels set by historic investment decisions and resultant network performance

Customer surveys over the last five years have indicated that customers' preferences for price and service levels are reasonably static – there is certainly no obvious widespread call for increased supply reliability. However TPCL does note the following issues:

- The service level called "Safety" is expected to continually improve as public perceptions and regulations are updated to decrease industry related risk.
- TPCL's cold storage customers require higher levels of continuity and restoration with interruptions to cooling and chilling being less acceptable as food and drink processing, storage and handling are subject to increasing scrutiny by overseas markets.
- Economic downturn may increase the incidence of theft of materials and energy.

3.4. Basis for Service Level Targets

Historical Trends

When setting TPCL's service level targets the recent history of these service level measures are taken into account and it is recognised that these measures will be difficult and typically slow to change. Historical results are trended and projected to forecast future service levels and then adjusted to account for any particular initiatives or other issues that are anticipated to affect service levels.

Targets for network reliability and for financial and energy efficiency targets are generally set at the forecast levels to help drive the completion of performance enhancement initiatives. Targets for customer satisfaction are set based on the desired outcome of achieving positive customer experiences while accepting that targeting 100% satisfaction would be unrealistic.

Results over the last five years for the key reliability and energy efficiency service levels for which TPCL sets service level targets are listed in Table 27 and customer satisfaction as indicated from past surveys are shown in Table 28.

Table 27: Reliability and Energy Efficiency History

Measure	2015/16	2016/17	2017/2018	2018/19	2019/20
SAIDI	225.92	139.90	202.5	199.4	255.7
SAIFI	3.39	2.16	2.69	2.73	3.50
Load Factor	64%	64%	61%	62%	61%
Loss Ratio	6.9%	6.%	6%	5.5%	5.8%
Capacity Utilisation	29.1%	28.6%	27.7%	29.4%	29.2%
Network OPEX / ICP	303	275	277	298	317
Network OPEX / km	1,217	1,097	1,120	1,211	1,300
Network OPEX / MVA	25,551	22,846	21,392	24,009	25,193
Non-Network OPEX / ICP	125	139	140	152	160
Non-Network OPEX / km	500	557	567	619	655
Non-Network OPEX / MVA	10,503	11,588	10,834	12,278	12,697

Table 28: Customer Satisfaction History

Attribute	Measure	2015/16	2016/17	2017/18	2018/19	2019/20
Planned Outages	Provided sufficient information. {CES}	96%	95%	95%	99%	99%
	Satisfaction regarding amount of notice. {CES}	98%	94%	98%	99%	98%
	Acceptance of one planned outage per year. {CES}	99%	97%	-	-	-
	Acceptance of retaining the current plan: 1 interruption of 4 hrs every 2 years. {CES}	91%	91%			
	Acceptance of one planned outage every two years lasting four hours on average. {CES}	-	-	80%	91%	64%
Unplanned Outages (Faults)	Power restored in a reasonable amount of time. {CES}	96%	79%			
	No impact or minor impact of last unplanned outage. {CES}	-	-	66%	72%	74%
	Information supplied was satisfactory. {CES}	92%	80%	79%	86%	78%
	PowerNet first choice to contact for faults. {CES}	45%	50%	33%	6%	17%
Supply Quality	Number of customers who have made supply quality complaints {IK}	14	5	7	3	8
	Number of customers who have justified complaints regarding supply quality {IK}	0	2	2	0	2

{ } indicates information source; CSS = Customer satisfaction survey undertaken by sending questionnaire to customers with invoices, CES = Customer engagement survey using independent consultant to undertake phone survey, IK = Internal KPIs

Benchmarking

In addition to trending of these results, benchmarking against other local distribution networks, as shown in Figure 28 to Figure 32, helps identify where TPCL might look to improve from current service levels. Any year to year changes predicted are expected to be small and need to be backed up by planned projects or initiatives which would impact service levels.

SAIFI – available EDB reliability results since 2015 show TPCL performance have been quite variable in the last two years, but due to the significant influence of storms, low customer density and region covered the performance is considered acceptable.

TPCL plans to normalise extreme events using the Commerce Commission DPP methodology. Forecast projections are calculated on historical rolling average performance.

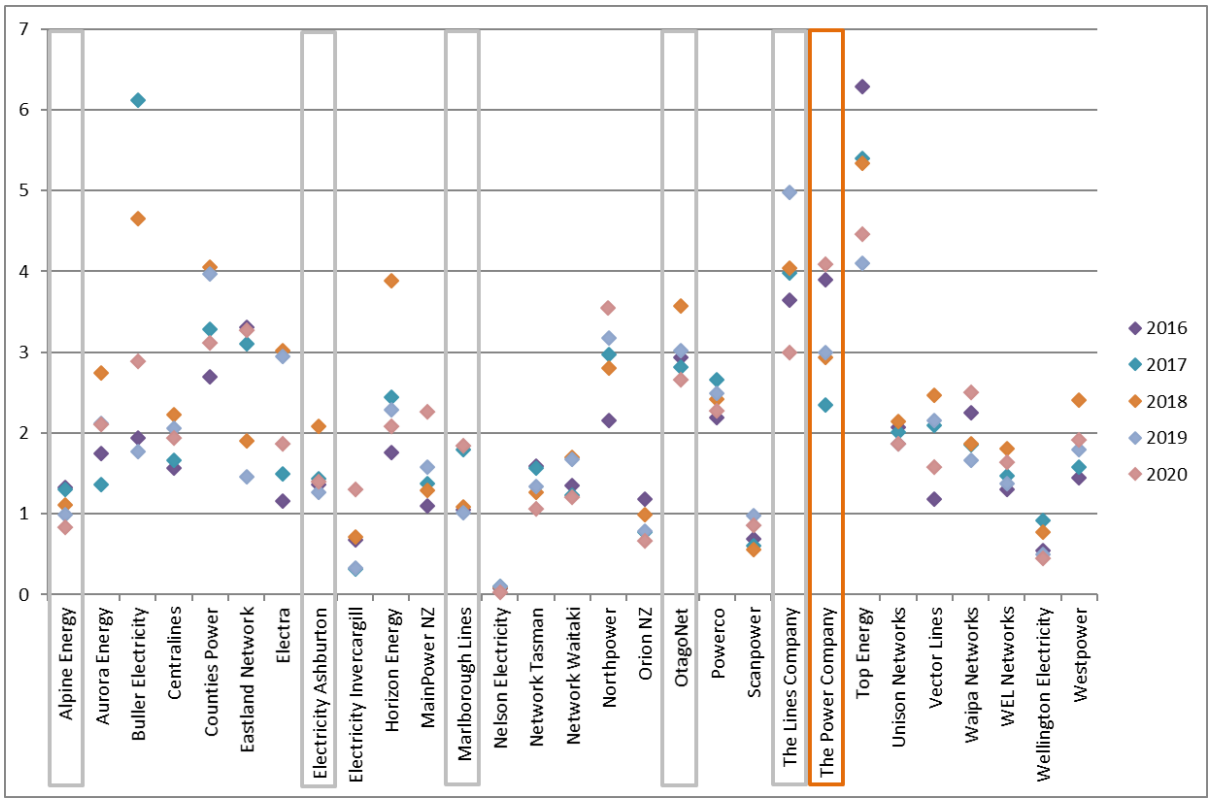


Figure 28: TPCL SAIFI Comparison with Local EDBs

SAIDI – available EDB reliability results since 2015 show TPCL have underperformed during the 2019/20 financial year.

This view is supported with the February 2020 customer survey result that 91% of TPCL customers were satisfied with the reliability of the power supply.

TPCL plans to normalise extreme events using the Commerce Commission DPP methodology. TPCL is installing SCADA enabled switches within the network and strategic locations to limit outage duration by improving restoration times.

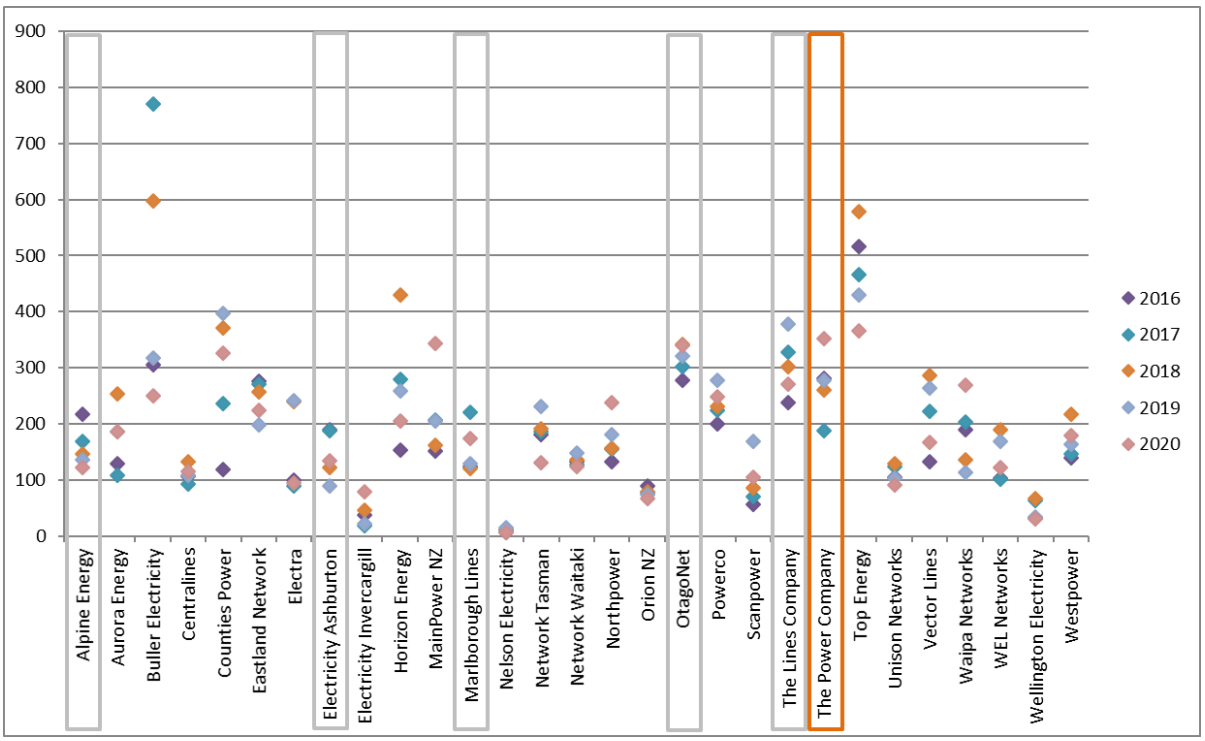


Figure 29: TPCL SAIDI Comparison with Local EDBs

Load Factor - LSI peak is due to New Zealand Aluminium Smelter (NZAS) and other network companies, with the most recent LSI peak occurring during winter.

Comparison with other networks shows that TPCL's load factor is average. TPCL is forecasting slight improvement due to transformer rationalisations planned.

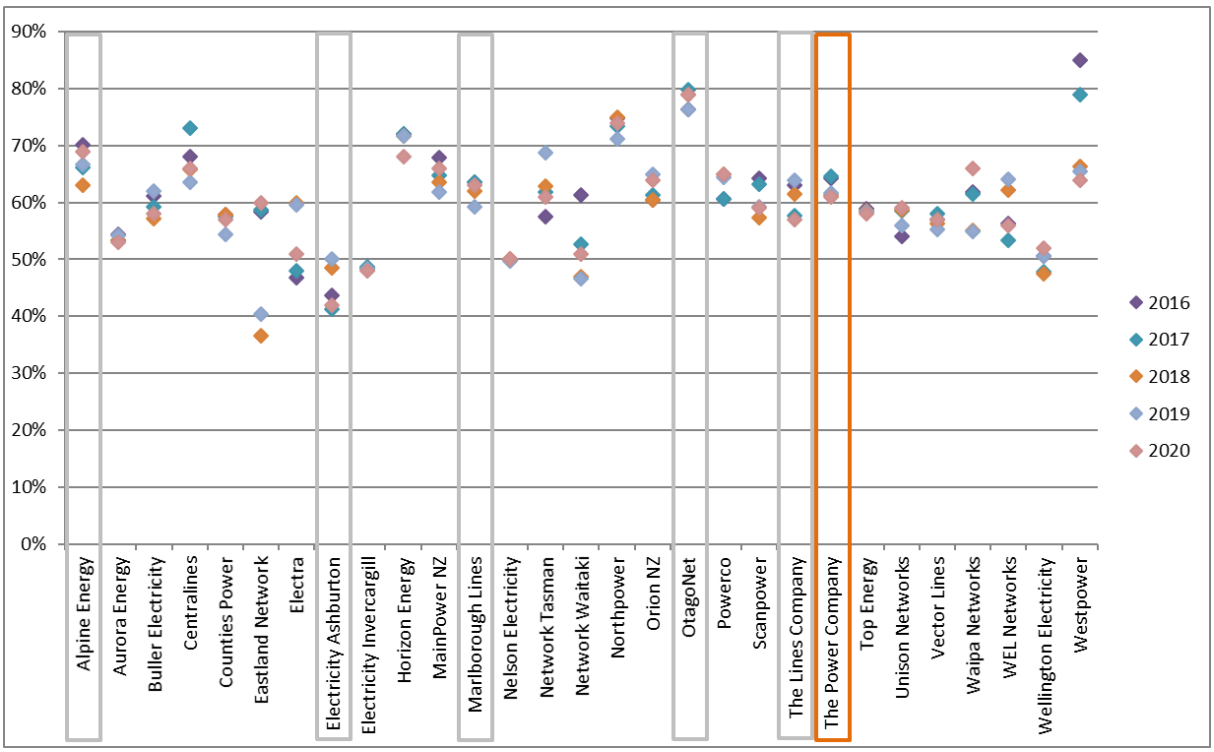


Figure 30: TPCL Load Factor Comparison with Local EDBs

Loss Ratio - Despite energy efficiency getting increasing focus it is generally uneconomic to improve the efficiency of primary assets to improve losses. Also as losses are paid for by retailers, there is no

financial incentive for the network company to reduce them apart from other technical issues such as poor voltage or current rating of equipment. Upgrading network equipment as growth occurs is expected to maintain losses at approximately present levels.

Comparison with other network companies shows TPCL's network is average. Trending over a five year period shows network losses are flat. TPCL can expect a long term average of less than 7% to be maintained. Year to year results can vary due to retailer estimations but variation is expected to reduce over time as the number of smart meters installed increases reducing the need for retailer estimation.

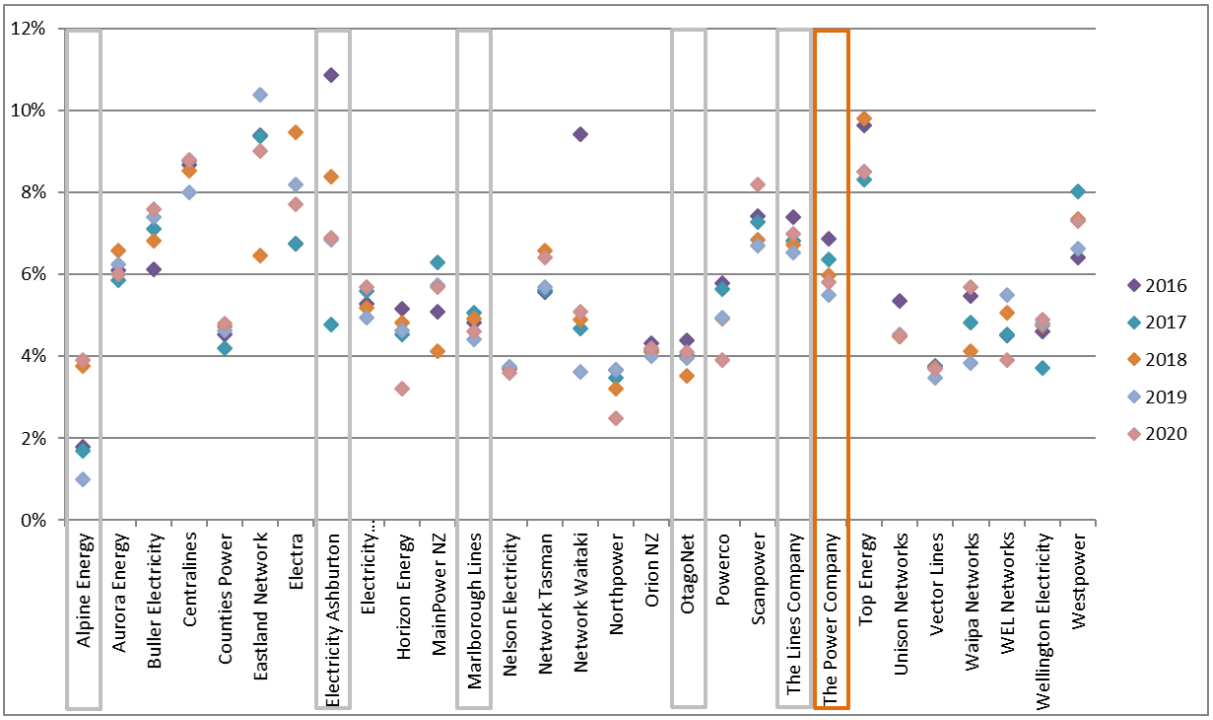


Figure 31: TPCL Loss Ratio Comparison with Local EDBs

Capacity Utilisation - Impact of expanding dairy industry is likely to impact with a large number of larger capacity transformers installed to supply new farms. The load profile on these is very peaky with no rationalisation[11] of transformers, as dairy sheds are normally distant from existing farm house. Only very minor improvement expected. Compared to other electricity lines businesses TPCL is average, therefore no change in strategy is planned. This metric is calculated from other reported information disclosure data.

[11] Rationalisation is where one transformer is used to supply multiple customers, with peaks occurring at differing periods a smaller installed capacity usually results. e.g. dairy shed transformer of 50kVA can normally supply the farm house, but due to distances usually requires its own 15kVA transformer.

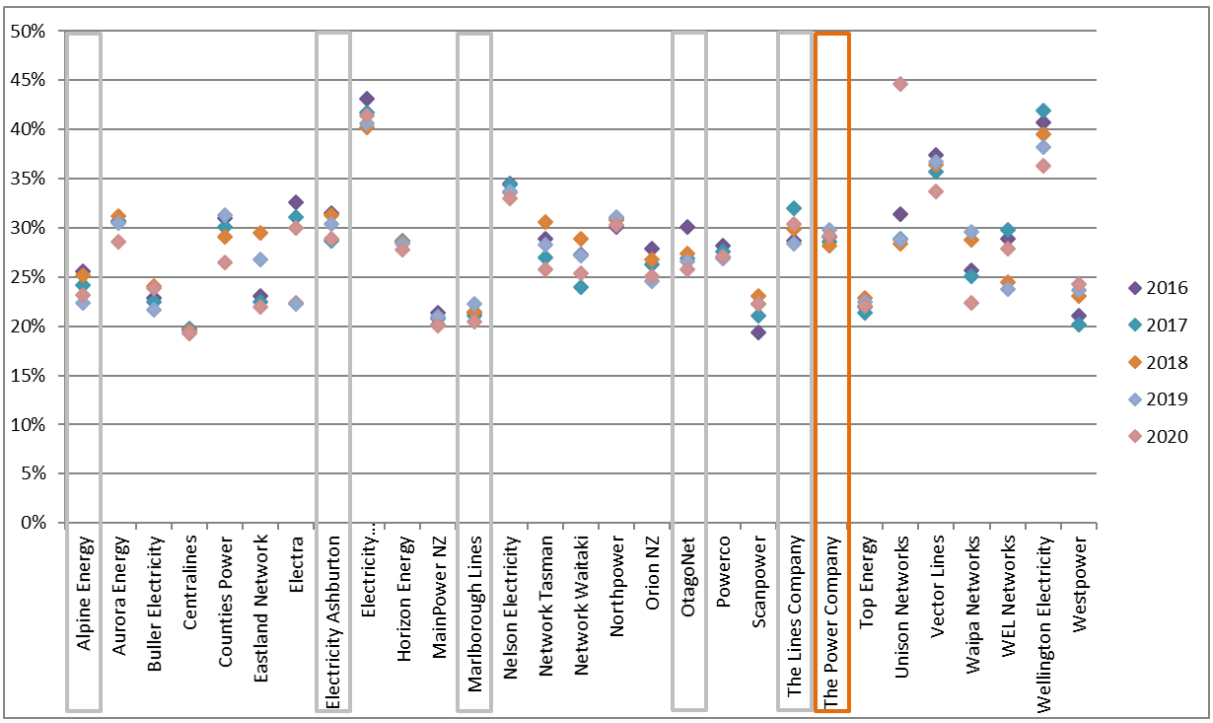


Figure 32: TPCL Capacity Utilisation Comparison with Local EDBs

Financial service levels – TPCL has redefined its financial service levels as discussed in section 3.2, comparison with similar lines companies must be made cautiously. When compared to the EDB's in its peer group, TPCL has the highest customer count, the second lowest connection density and the middle level of connected distribution transformer capacity. This results in unfavourable metrics on the /km measures.

Examination of Figure 33 to Figure 38 shows that both Network OPEX and Non-Network OPEX are in line with or ahead of peers once adjustment is made for distortion of the /km metrics as described above.

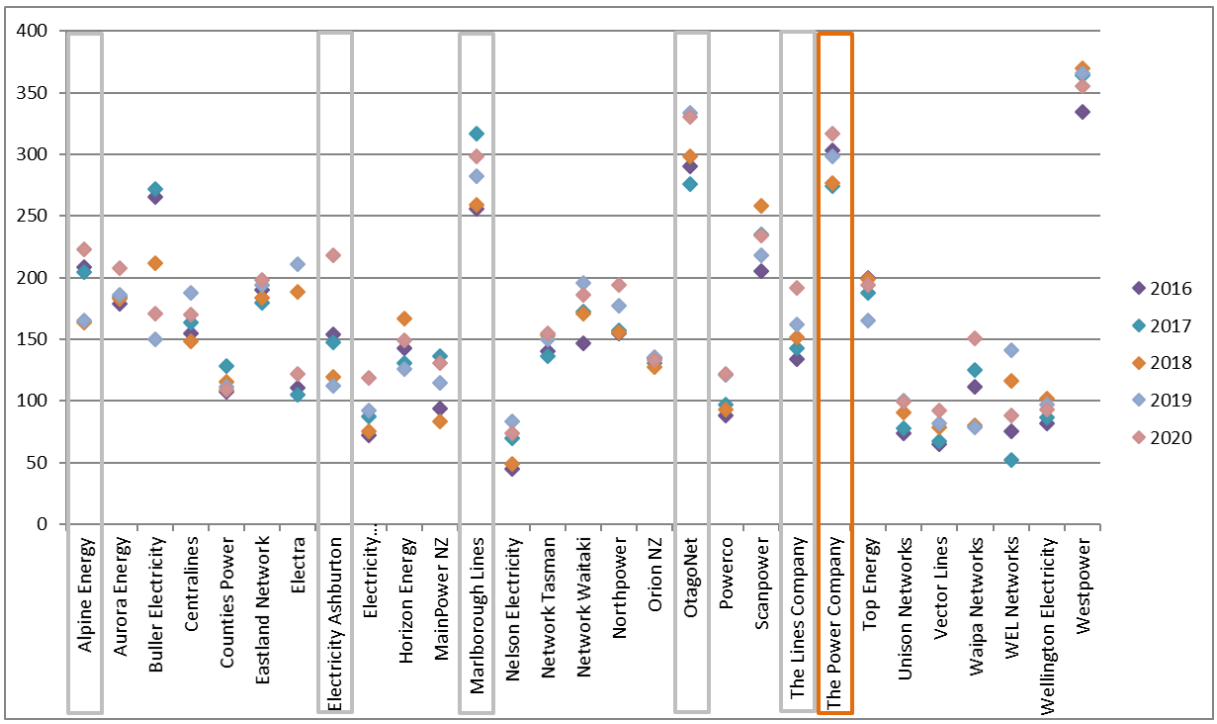


Figure 33: TPCL Network OPEX/ICP Comparison with Local EDBs

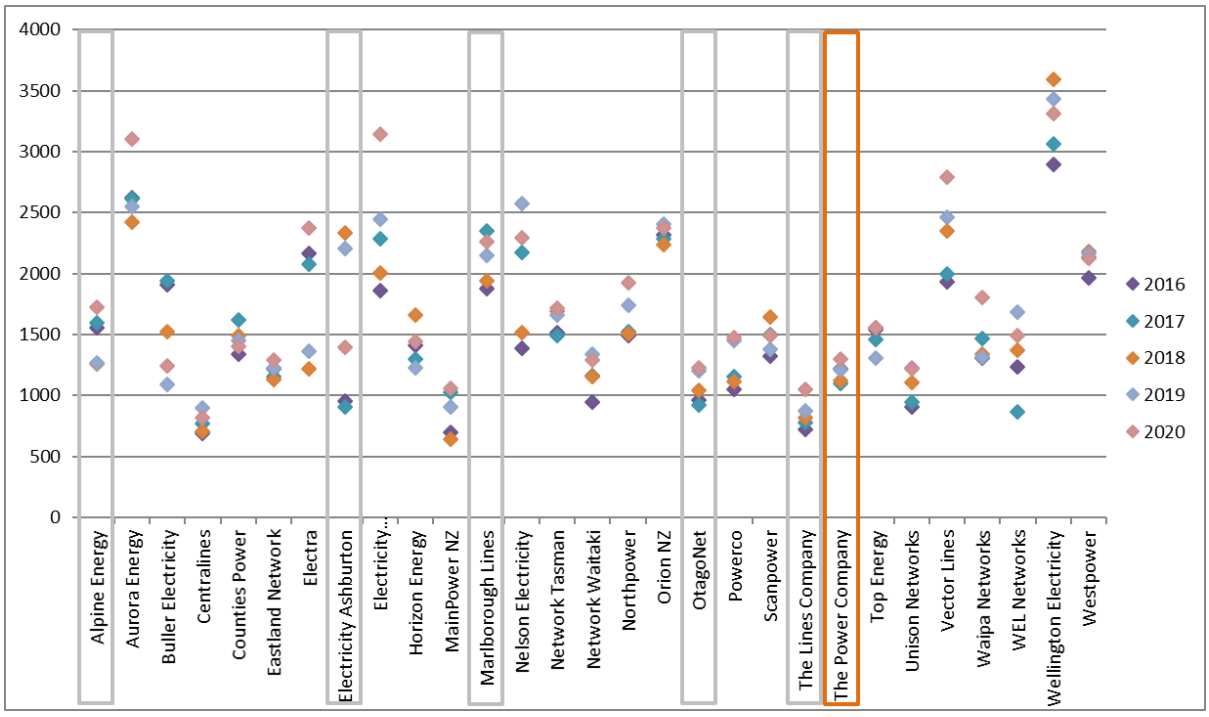


Figure 34: TPCL Network OPEX/km Comparison with Local EDBs

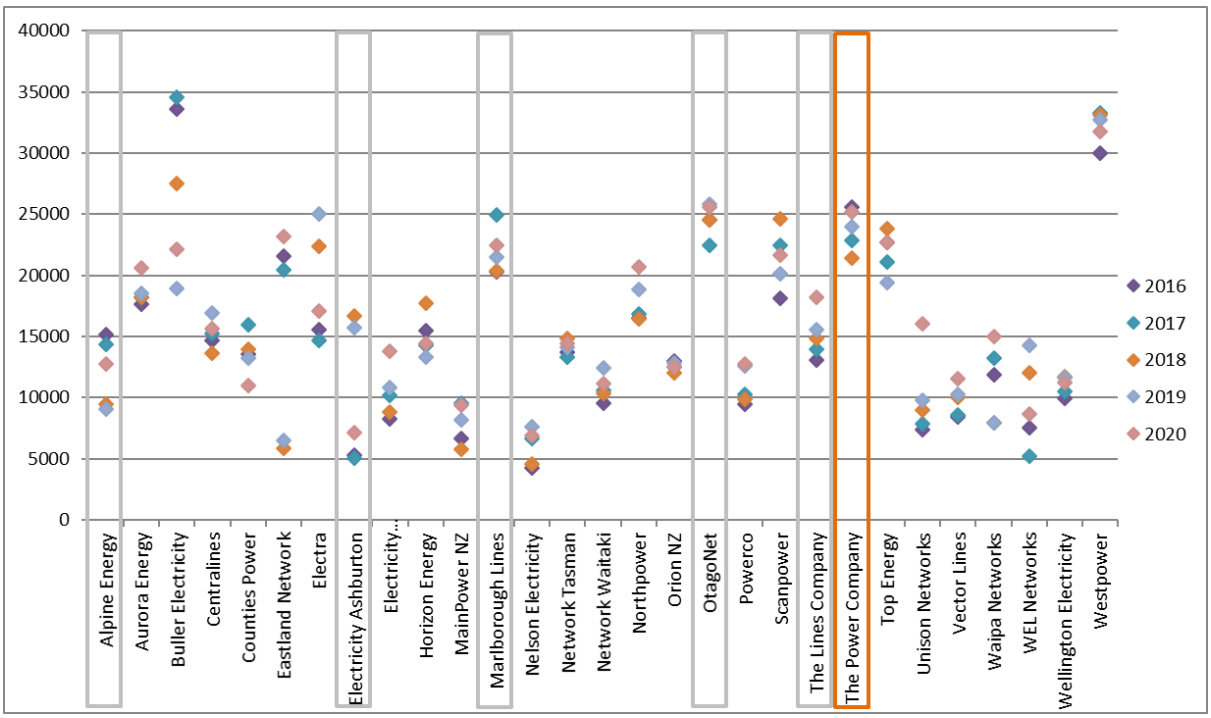


Figure 35: TPCL Network OPEX/MVA Comparison with Local EDBs

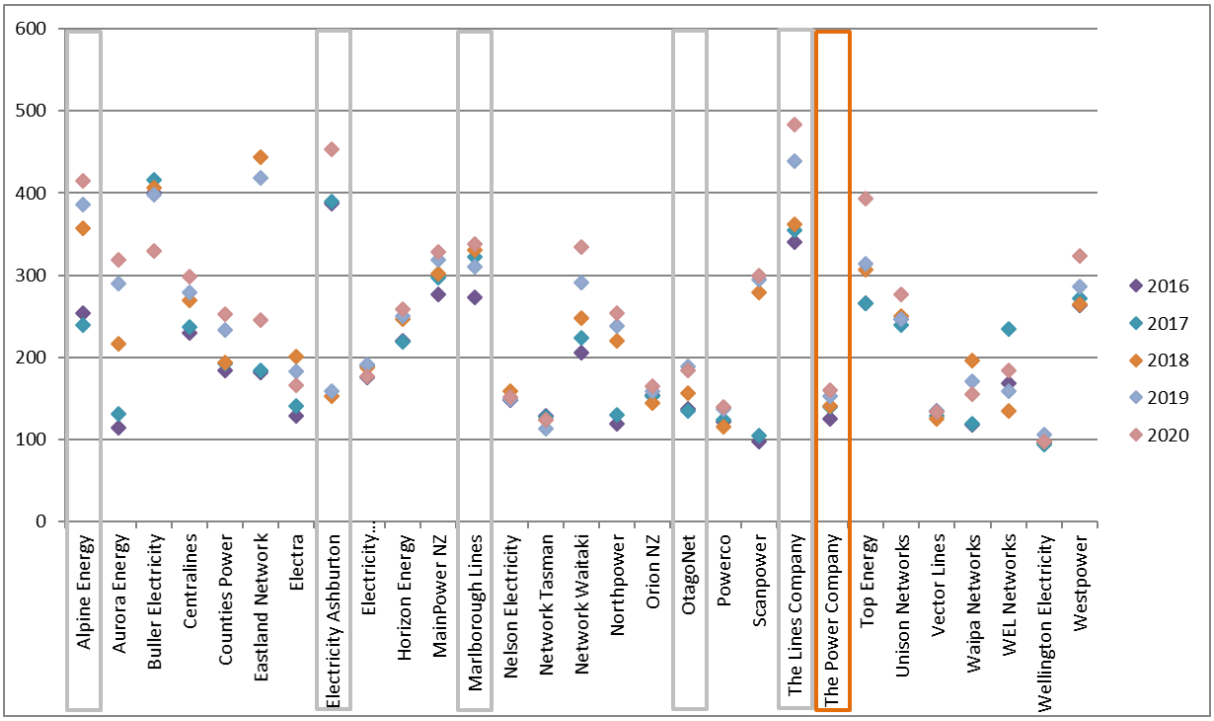


Figure 36: TPCL Non-Network OPEX/ICP Comparison with Local EDBs

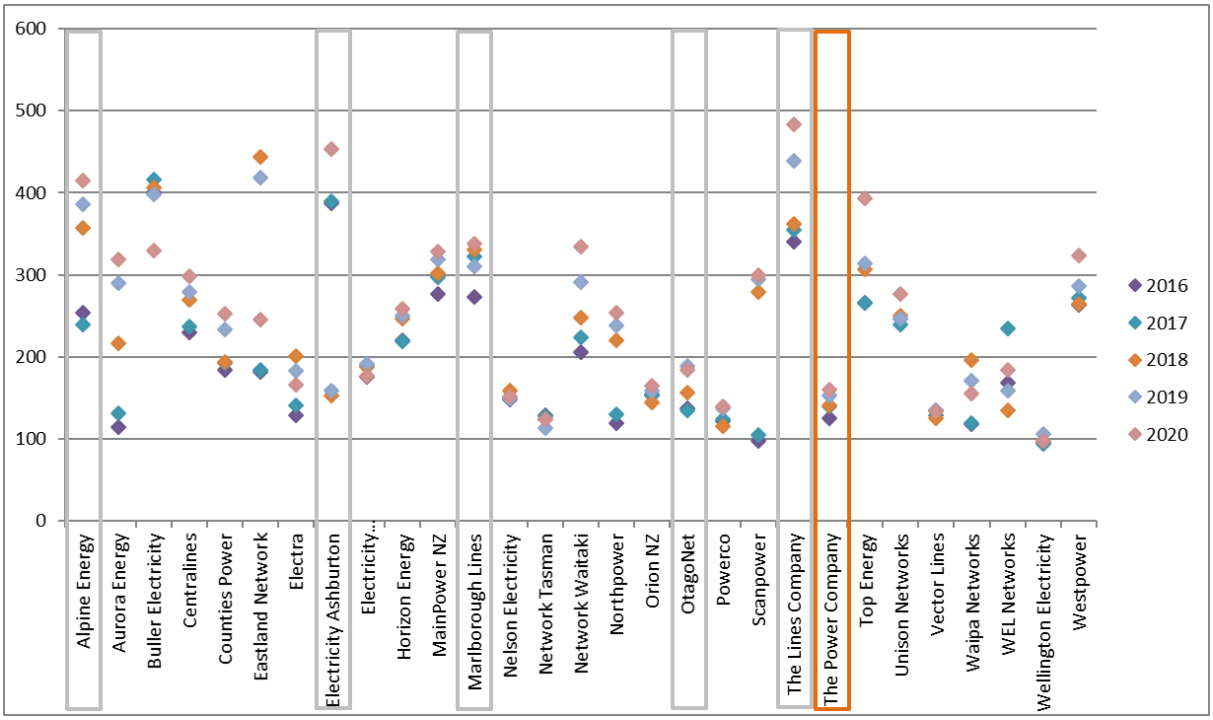


Figure 37: TPCL Non-Network OPEX/km Comparison with Local EDBs

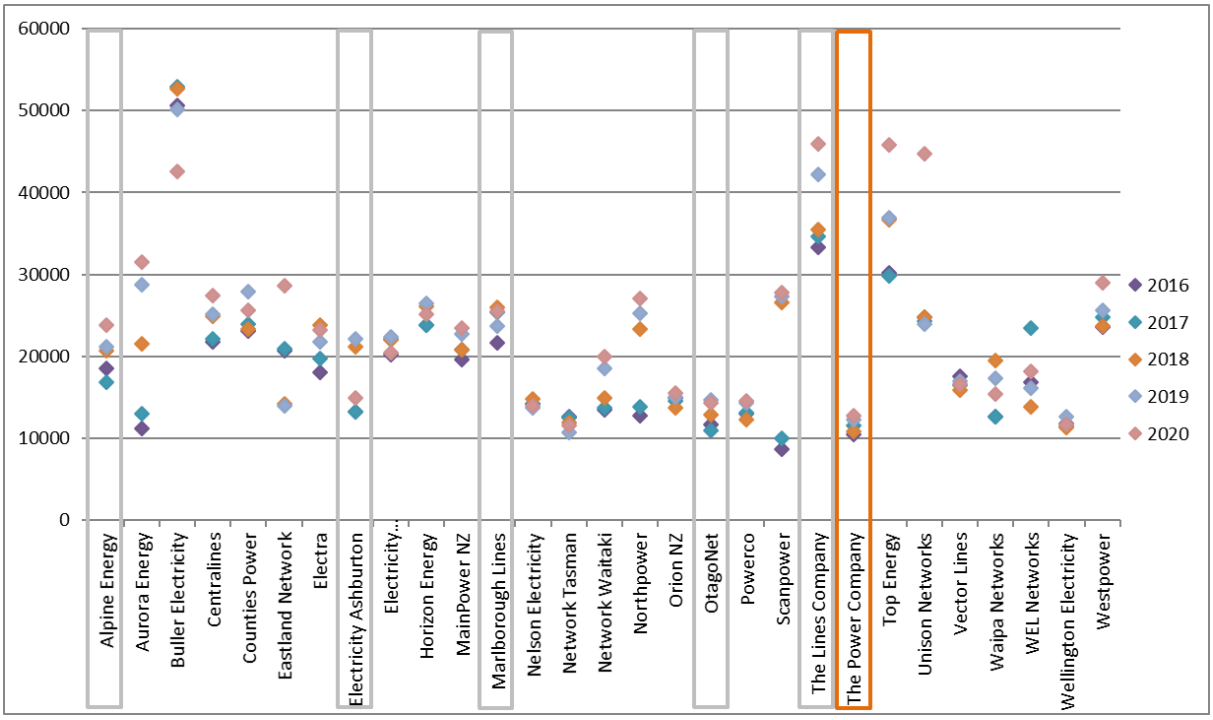


Figure 38: TPCL Non-Network OPEX/MVA Comparison with Local EDBs

4. Development Planning

TPCL monitors the existing network assets and ensures their operation within limits imposed by capacity constraints and service level requirements. Regular updating of demand forecasts enables predictions for future network operation and in line with TPCL's development criteria helps identify the need for network development.

4.1. Development Criteria

Network development is primarily associated with creating additional network capacity for supplying increasing demand (customer load). Large generation or an aggregation of many small generators may also become the dominant driver for increased capacity on some areas of the network. Requirements for maintaining or improving service levels, whether driven by statute, customer and other stakeholders' desire or internal strategic initiatives, also create development drivers. While asset renewal is generally a lifecycle management requirement it may present an opportunity as the most economic time for development initiatives such as additional capacity, the introduction of new technology or more efficient alternative solutions.

Network developments are triggered by events that necessitate changes to network capacity or service levels. These trigger events may directly dictate a development requirement. For example, a connection request from an intending customer requires an increase in network capacity to match their additional load requirements. They may also be less direct such as when load growth exceeds a threshold for increased security; the security trigger threshold being predetermined based on a strategic "line in the sand" designed to provide particular service levels when applied consistently across the network. Identified development triggers and the thresholds at which they are set form the key criteria for TPCL's network development planning.

Growth Based Development Triggers

At its most fundamental level, demand is created by individual customers drawing (or injecting) energy through their individual connection points. The demand at each connection aggregates "up the network" through LV reticulation to the distribution transformer, then through the distribution network, the zone substation, the subtransmission network to the GXP and ultimately through the grid to the power stations. Load diversity tends to favour better load factor and capacity utilisation more and more with this aggregation of load up the network.

Demand growth creates the predominant driver for network development and therefore growth triggers have been identified and where appropriate corresponding thresholds have been set to achieve desired service levels. These development triggers provide simple scenario based indicators for development requirements although reliability incorporates probabilistic considerations. In meeting future demand while maintaining service levels, the first step is to determine if the projected demand will exceed any of TPCL's defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 29.

If a trigger point is exceeded TPCL will then move to identify a range of options to bring the asset's operating parameters back to within the acceptable range of trigger points. These options are described later in this section (see Cost Efficiency) which also embodies an overall preference for avoiding new capital expenditure. As new capacity has balance sheet, depreciation and ROI implications for TPCL, endeavours will be made to meet demand by other, less investment-intensive means. This discussion also links strongly to TPCL's discussion of asset life cycle in Lifecycle Planning.

Table 29: Development Triggers and Typical Network Solutions

Development	Trigger Point	Typical Network Solution
Extension	New customer requests a connection outside of the existing network footprint; often within network area but not immediately adjacent to existing infrastructure.	New assets are required to extend the network to the new customer. Additional capacity may also need to be built into the nearest existing network and upstream assets depending on customer size.
Capacity	Load exceeds capacity rating of network assets (or encroaches on spare capacity required to be maintained) or voltage drops below acceptable levels; i.e. below 0.94pu at customer's premises. Proactively identified through network modelling and monitoring load data from meters or MDI[12]s but may occasionally manifest as overload protection operation, temperature alarms or voltage complaints. The current roll out of smart meters will vastly improve ability to estimate loading and utilisation of asset capacity.	Replace assets with greater capacity assets. May utilise greater current ratings or increase voltage level (extension of higher voltage network, use of voltage regulators to correct sagging voltage or introduction of new voltage levels). Alternative options are considered prior to these capital intensive solutions but generally provide a means to delay investment; may be network based such as adding cooling fans to a zone substation transformer or non-network e.g. controlling peak demand with ripple control.
Security and Reliability	Load reaches the threshold for increased security as defined in TPCL's security standard set out later in this section (see Security Standards). Customers, especially large businesses, may request (and be willing to provide a capital contribution for) increased security.	Duplicating assets to provide redundancy and continued supply after asset failures. Increase meshing/interconnection to provide alternative supply paths (backups). Additional switching points to increase sectionalising i.e. limit amount of load which cannot have supply reinstated by switching alone after fault occurrence. Automation of switching points for automatic or remote sectionalising or restoration.

Service Level Changes

The general approach of monitoring network demand and initiating projects when standardised development triggers are reached, serves to maintain existing service levels. Where a change in service level is desirable, this may be undertaken either directly (e.g. targeted seismic remediation program to improve safety and reliability under earthquake conditions), or indirectly through the adjustment of the thresholds used for the triggers (e.g. lowering the minimum number of downstream customers required to justify a dual transformer substation). Decisions to change service levels tend to be strategic in nature and go beyond the general approach of monitoring network demand and initiating projects when standardised development triggers are reached.

These projects may be triggered by a complex interaction of many factors or driven (or required) by external influences. Justification for these projects will be discussed later in this section (see Development Programme). Examples are the shifting perceptions around staff/personnel safety or acceptable levels of risk and these will create drivers for network development projects which are not a requirement arising from demand growth.

[12] MDI = Maximum Demand Indicator

Relationship with Lifecycle Maintenance

It is important to understand the relationship between network development, lifecycle management practices and the network service levels discussed in section Service Levels. Demand growth on fixed network assets erodes supply reliability over time as a greater number of customers or level of demand is affected when a supply interruption occurs. Using increased network maintenance to preserve network reliability against demand growth requires a shift away from the most economic asset age profiles (generally about 50% average life) which then must be sustained so this approach is uneconomic as well as inherently limited. Essentially with a long term view, lifecycle maintenance counteracts declining reliability in the face of network aging and deterioration while network development counteracts declining reliability in the face of demand growth.

Cost Efficiency

In the interests of cost efficiency, TPCL aims to minimise capital expenditure when determining the most appropriate development option for the network. Being cost efficient with network development requires a "just enough, just in time" approach for the determination of appropriate new capacity as well as an appropriate level of standardisation. Other works within the locale may be brought forward and combined to achieve economies of scale for design, safety and traffic management costs.

Before capital intensive upgrades are required the following actions, in a broad order of preference, are considered as solutions when development triggers have been reached.

- Do nothing and simply accept that one or more parameters have exceeded a trigger point. In reality, do nothing options would only be adopted if the benefit-cost ratios of all other reasonable options were unacceptably low and if assurance was provided to the Chief Executive that the do nothing option did not represent an unacceptable increase in risk to TPCL. An example of where a do nothing option might be adopted is where the voltage at the far end of a remote rural feeder drops below the network standard minimum level for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low.
- Operational activities, in particular switching on the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Demand management using load control or using other methods to influence customers' consumption patterns so that assets operate at levels below trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source to avoid new capacity. TPCL notes that the effectiveness of line tariffs in influencing customer behaviour is diminished by the retailer's practice of repackaging fixed and variable line charges.
- Install generation or energy storage units so that an adjacent asset's performance is restored to a level below its trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. waste steam from a process.
- Modify an asset so that the asset's trigger point will move to a level that is not exceeded e.g. by adding forced cooling. This approach is more suited to larger classes of assets such as power

transformers. Installation of voltage regulating transformers may be economic where voltage drops below acceptable levels but current capacity is not fully utilised.

- Retrofitting high-technology devices that can exploit the features of existing assets including the generous design margins of old equipment. An example might include using advanced software to thermally re-rate heavily-loaded lines, using remotely switched air-break switches to improve reliability or retrofit core temperature sensors on large transformers to allow them to operate closer to temperature limits.

Installing new or greater capacity assets is generally the next step which increases asset capacity to a level at which the relevant trigger point is not exceeded. An example would be to replace a 200kVA distribution transformer with a 300kVA unit so that the capacity criterion is not exceeded.

For meeting future demands for capacity, reliability, security and supply quality there may be several options within the above range of categories and identifying potential solutions is dependent on the experience and ingenuity of the Engineers undertaking the planning.

Standardisation

Standardisation is an important strategy used by TPCL to achieve cost efficiencies. It may not always be obvious that standardisation achieves this outcome; standardised equipment sizes will often mean larger equipment is used than would otherwise be strictly necessary. However standardising assets allows efficient management of stock and spares, operator familiarisation, standardisation of operation procedures, and simplified selection of equipment and materials. Also standardised designs or design criteria avoids “reinventing the wheel” each time, can incorporate more lessons learnt than could otherwise be practically managed and simplifies the design process. The benefits of standardisation easily outweigh the oversizing of assets where significant repetition of a particular network solution occurs.

PowerNet’s Quality Systems (policies, standards and procedures) provide for the documentation and communication of the standards that are applied to TPCL’s network. TPCL benefits from their close working relationship with the other line owners whose networks are managed by PowerNet with the standardisation able to be maintained across networks for increased efficiencies. Examples include the keeping of critical spares, which can be more efficiently achieved when shared across the combined network’s asset base or lessons learnt on one network can be incorporated into standards which then benefit the other networks to which they are applied. Standardised design is used for line construction with a Construction Manual and standard drawings in use by Field Staff / Contractors / Designers / Planners.

Standardised designs for projects may be used from time to time where projects with similarities occur within a short enough period of time. Though these opportunities do not arise often on TPCL’s network, similar projects are often managed by PowerNet on other networks and where project scopes overlap design “building blocks” may be utilised in several designs. Through this approach a degree of standardisation is achieved with each consecutive design utilising these building blocks from the latest previous design. Continuous improvement is realised with lessons learnt able to be incorporated at each iteration.

Virtually all of TPCL network assets are standardised to some degree either by being an approved network material or asset type or by selection and installation in line with network standards. Examples of standardisation are listed in Table 30:

Table 30: Equipment Standardisation

Component	Standard	Justification
Underground Cable	Distribution and low voltage network: 35, 95, 185 & 300mm²Al	Stocking of common sizes, lower cost
	11kV or 400V Cable Cross-linked Polyethylene (XLPE)	Rating, ease of use.
Overhead Conductor	Subtransmission and distribution: All aluminium alloy conductor (AAAC) - Chlorine, Helium, Iodine, Neon	Low corrosion, low resistance, cost, stocking of common sizes
	Aluminium conductor steel reinforced (ACSR) – Flounder, Wolf	Higher strength (longer spans, snow load)
	Low Voltage Aerial Bundled Cable (ABC): 35, 50 & 95mm²Al (four core)	Safety, lower cost.
Structures	Poles: Busck pre-stressed concrete	Consistent performance, long life, strength
	Cross-arms: Solid hardwood	Long life, strength.
Line equipment	Standard ratings (e.g. ABS 400A, field circuit breaker 400A), manufacturer/type	Cover-all specification, minimise spares, familiarity, environmental (non SF_6)
Power Transformers	Discrete ratings, tap steps, vector group, impedance, terminal arrangements etc.	Ratings match available switchgear ratings, interchangeability, network requirements.
33kV & 11kV Switchboards	Common manufacturers, common specification.	Interchangeability, spares management.
Protection and Controls	Common manufacturer, communications interface, supply voltage etc.	Minimise spares, familiarity, proven history
Substation equipment	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history
Distribution Transformers	Standard ratings (residential areas - size based on domestic customer numbers), equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.
Ring Main Units	Standard ratings, equipment type, manufacturer etc.	Minimise spares, familiarity, proven history, cover-all specification.

Security Standard

Security is the level of redundancy that is built into the network to provide improved continuity of supply when faults occur. It enables supply to be either maintained or restored independently of repairing or replacing a faulty component. TPCL's security standard is therefore crucial for the maintenance of network reliability levels. Security involves a level of investment beyond what is strictly required to meet demand and therefore maintenance of desired security must avoid demand growth eroding surplus capacity which can easily occur. Typical approaches to providing security include:

Provision of alternative supplies: achieved by providing one or more inter-feeder tie switches (interconnection points), this requires those adjacent feeders to maintain spare capacity. Urban areas can naturally achieve a high level of meshing with many tie points between feeders whereas rural area feeders may need significant line extension to meet adjacent feeders. The number of switches effectively dividing up a feeder also contributes to security, with the greater the number, the smaller the section which must be isolated after a fault for the duration of the repair.

Duplication of assets: so that in normal service both sets of assets share the load. Then when a duplicated asset malfunctions it can be isolated and all load is transferred to the remaining asset. This approach generally provides the greatest security as there is typically no interruption to supply though

duplication of assets tends to be more expensive than merely allowing greater capacity in existing adjacent assets.

Use of generation: may be used to either provide an alternate supply or at least supplement supply and reduce capacity requirements for backup assets. To be of any use from a security perspective, generation would need to have close to 100% availability. Diesel generation has good availability so is practically able to be used occasionally to manage network constraints though it is too expensive to run for extended periods. Other forms of generation such as run-of-the-river hydro, wind or solar, do not provide the needed availability due to lack of energy storage so cannot be relied on to respond to varying load or provide sufficient generation during peak demand periods.

Use of demand management: (interruptible load) can be used to avoid security triggers based on load level or avoid capacity of backup assets being exceeded.

The preferred means of providing security to urban zone substations will be by secondary subtransmission assets with any available back-feeding on the 11kV providing a third tier of security. Table 31 summarises the security standards adopted by TPCL. Where a substation is for the predominant benefit of a single customer, their wish for security will over-ride this standard.

Table 31: Target security levels

Description	Load type	Security level
AAA	Greater than 12MW or 6,000 customers.	No loss of supply after the first contingent event (or <60 second change over)
AA	Between 5 and 12MW or 2,000 to 6,000 customers.	All load restored within 25 minutes of the first contingent event.
A(i)	Between 1 and 5MW	All load restored by isolation and back-feeding. Isolated section restored after time to repair.
A(ii)	Less than 1MW	All load restored after time to repair.

Table 32: Zone Substation security levels

Zone Substation	Current Security Level	Required Security Level	Remarks
Athol	A(i)	A(i)	
Awarua Chip Mill	A(ii)	A(ii)	
Bluff	AAA	AA	
Centre Bush	A(i)	A(i)	
Colyer Road	AAA	AAA	
Conical Hill	AAA	A(i)	Sawmill closed
Dipton	A(i)	A(i)	
Edendale Fonterra	AAA	AAA	
Edendale	AAA	AA	Fonterra down-stream plant supplied off this substation
Glenham	A(i)	A(i)	
Gorge Road	A(i)	A(i)	
Heddon Bush	AA	AA	Switching Station??
Hedgehope	A(i)	A(i)	
Hillside	A(ii)	A(ii)	
Isla Bank	A(i)	A(i)	
Kelso	A(i)	A(i)	
Kennington	A(ii)	AA	Second 33kV line in 2020/21
Lumsden	A(i)	A(i)	
Makarewa	AAA	AA	

Zone Substation	Current Security Level	Required Security Level	Remarks
Mataura	AA	AA	Can switch over to Edendale GXP
Monowai	A(ii)	A(ii)	
Mossburn	A(i)	A(i)	
North Gore	AAA	AAA	Gore Hospital supplied off this substation
North Makarewa	AAA	AAA	Spare supply transformer at Mossburn
Ohai	AA	A(i)	
Orawia	A(i)	A(i)	
Otatara	A(i)	A(i)	
Otautau	A(i)	A(i)	
Racecourse Road (EIL)	A(i)	A(i)	
Riversdale	A(i)	AA	Tee off 33kV supply has no alternative
Riverton	AAA	AA	Spare 66/11kV 5/7.5MVA transformer in service at this site.
Seaward Bush	AAA	AAA	Southland hospital supplied off this substation.
South Gore	AAA	AAA	Supplies Gore CBD.
Te Anau	AAA	AAA	Main tourism centre.
Tokanui	A(i)	A(i)	
Underwood	AAA	AAA	
Waikaka	A(i)	A(ii)	
Waikiwi	AA	AAA	Need to switch-over to alternate 33kV if supplying 33kV faults.
Winton	AAA	AAA	
White Hill (Wind)	A(i)	A(i)	
Monowai (Hydro)	AAA	AAA	

[Green-Over Red – Under]

Determining Capacity

When new or increased capacity has been determined as necessary the amount of new capacity must be quantified. Appropriate asset sizing is balanced to fit within TPCL's guiding principle of minimising the long term cost of service of sufficient quality ahead of demand.

Sizing network equipment carries an investment risk for assets being under-utilised if not done correctly. While sizing a particular asset for the present time is relatively straight forward, load growth makes appropriately sizing an asset more difficult, especially for asset lifetimes over periods of high growth and growth unpredictability. Installing assets with too much spare capacity means an over-investment, however if assets are undersized the asset will need to be replaced early before their natural end of life. In many cases standardisation will limit the options available to assist in the selection of capacity. In general, this will mean the balancing of over-investment and under-investment will result in a small amount of over-investment (i.e. increased capacity). However, this is considered to be optimal, due to the often marginal cost of increased capacity versus significant cost of re-work should the investment prove to be under-sized.

Stranding of assets is a risk where new assets are required to supply one (or few) new customers representing the worst case in over-investment if the expected growth does not eventuate. This stranding risk is particularly significant when network extension outside of the existing network footprint is required as the assets are less likely to be re-utilised if the expected load disappears. Stranding risk is generally managed through capacity guarantee contracts with customers to recover expected line charges if necessary.

Relocation of assets provides a way to manage costs efficiently while limiting exposure to the above risks in areas of growth. However this strategy is only of benefit where the material cost dominates the installation cost of establishing an asset; the installation cost cannot be recovered. For example once load grows to a power transformer's capacity the transformer can be relocated and used elsewhere so that a larger unit may be installed in its place. In comparison a cable (where trenching and reinstatement dominates installation costs) would typically be abandoned and replaced.

Examples of criteria to determine capacity of equipment in line with the above considerations are as shown in Table 33. Clearly understanding load growth into the future is crucial to making sound investment decisions. The method and considerations for forecasting network demand is discussed later in this section.

Table 33: Capacity Selection Criteria

Network Asset	Capacity Criteria Selection
Subtransmission network	Allow expected demand growth over life time of assets
Power transformers	Allow expected demand growth over 20 years then relocate
Switchgear	Allow expected demand growth over life time of assets
Distribution and LV cables	Allow growth over expected life when known or otherwise 100% growth over existing load
Overhead distribution and LV lines	Build to standard volt drop from nominal; Urban: 11kV: -3%, LV: -5% Rural: 11kV: -4%, LV: -4%
Distribution transformers	Size based on diversity and anticipated medium term load; Domestic Customers / Transformer Size 2 / 15kVA 6 / 30kVA 10 / 50kVA 20 / 100kVA 50 / 200kVA 80 / 300kVA 150 / 500kVA Individual customers / Size to customer requirements

Energy Efficiency

TPCL strives to make decisions based on the best outcome for its customers and as customers pay for losses on the network in their energy bills, cost benefits are considered in delivering energy as efficiently as possible. However selection of more efficient assets rarely is justified as a cost benefit to customers. In the few cases where there is an economic justification to reduce losses in this way TPCL will use these solutions, for example specifying low loss cores used in the magnetic circuits of transformers. Otherwise power consumed by TPCL and its organisational partners is used responsibly with heating of substation buildings and PowerNet's office buildings heated using efficient heat pump technology, insulation and draft control etc. where appropriate.

Additionally TPCL formed the Southland Warm Homes Trust (SWHT) in 2008 with EIL. The SWHT works in partnership with government, the Energy Efficiency and Conservation Authority (EECA) and local funders to provide subsidies for insulation and heating assessments and retrofits for warmer,

healthier homes across the Deep South region. PowerNet provides administration and financial reporting services on behalf of the (SWHT).

The SWHT contracts Awarua Synergy to carry out assessments and the installation of insulation and heating products on behalf of the Trust. Under EECA's Warm Up NZ Healthy Homes program which came into effect on 1 July 2013, insulation is free for eligible homeowners. Landlords with eligible tenants are also included but will be required to make a contribution. The Healthy Homes scheme targets those who stand to benefit most from having their homes insulated, those being low income households with high health needs, including families with children and the elderly. EECA provides 50% of the funding conditional upon the remaining 50% funding coming from third party funders.

Identifying the Best Option

Of the many possible development options that may be identified for meeting demand and service levels, the option which best meets TPCL's investment criteria is determined using a range of analytical approaches. Each of the possible approaches to meeting demand will contribute to strategic objectives in different ways. Increasingly detailed and comprehensive analytical methods are used for evaluating more expensive options. Table 34 summarises the decision tools used to evaluate options depending on their cost.

Table 34: Decision Tools Used Based on Cost

Cost and Nature of Option	Decision Tools	Approval Level
Up to $75,000, commonly recurring, individual projects not tactically significant but collectively add up.	TPCL standards. Industry rules of thumb. Manufacturer's tables and recommendations. Simple spreadsheet model based on a few parameters.	Project Manager
Up to $250,000, individual projects of tactical significance. Timing may be altered to allow resource focus on higher priority projects.	Spreadsheet model to calculate NPV that might consider one or two variation scenarios. Basic risk analysis including environmental and safety considerations. Project Charter incorporated with a staged gate approval Consultation with stakeholders if necessary.	General Manager Asset Management
Up to $1,000,000, individual projects likely to be strategically significant. Timing may be altered to allow resource focus on higher priority projects.	Extensive spreadsheet model to calculate NPV that might consider several variation scenarios. Risk analysis including environmental and safety considerations and consideration of risk management costs. Project Charter incorporated with a staged gate approval Consultation with stakeholders if necessary.	Chief Executive
Over $1,000,000, several each year, likely to be strategically significant. May divert resources from routine lower cost projects in the short term.	Extensive spreadsheet model to calculate NPV, payback that will probably consider several variation scenarios. Detailed risk analysis including environmental and safety considerations - represented as cost estimates within NPV and Payback calculations. Resources (financial, workforce, materials, legal) across AWP need to be balanced across many projects and several years managed through planning meetings and spreadsheet models.	Board Approval

Cost and Nature of Option	Decision Tools	Approval Level
	Project Charter incorporated with a staged gate approval Ongoing stakeholder consultation may be required especially large customers. Business case presented to the Board highlighting options considered and justification of recommended option.	

Prioritising Development Projects

Development projects are prioritised in line with the principles set out in Drivers and Constraints – Managing Conflicting Stakeholder Interests when competition for resources exists. Safety, viability, pricing, supply quality and compliance is the order of priority for managing these conflicts. These factors cannot be applied absolutely as each project will have its own combination of these factors presenting in various degrees. Instead a weighting approach is used recognising the relative severity of these factors between projects and their importance relative to each other. Each factor also implicitly recognises risk however this may need to be rationalised as it affects the AWP as a whole. The resulting prioritised AWP is presented to TPCL Board for approval with supporting justification in the updated AMP.

4.2. Forecasting Demand and Constraints

As development projects can take many months or even years to complete, understanding when trigger points may be exceeded in the future is necessary to ensure capacity can be made available by the time it is needed. This involves demand forecasting based on trends taken from historical data as well factoring in the many demand drivers which may cause future deviation from status quo trends.

TPCL's Current Demand

TPCL's maximum demand (MD) of 146.72 MW did not occur at the same time as the Lower South Island (LSI) peak which occurred at 8:00 on the 23rd of August 2019. All of the GXPs which provide supply to TPCL had maximum demands which occurred at a different time to both the overall TPCL MD and the LSI peak. TPCL coincident demand at the time of the LSI peak was 116.43 MW. The individual maximum demands are shown in Figure 39.

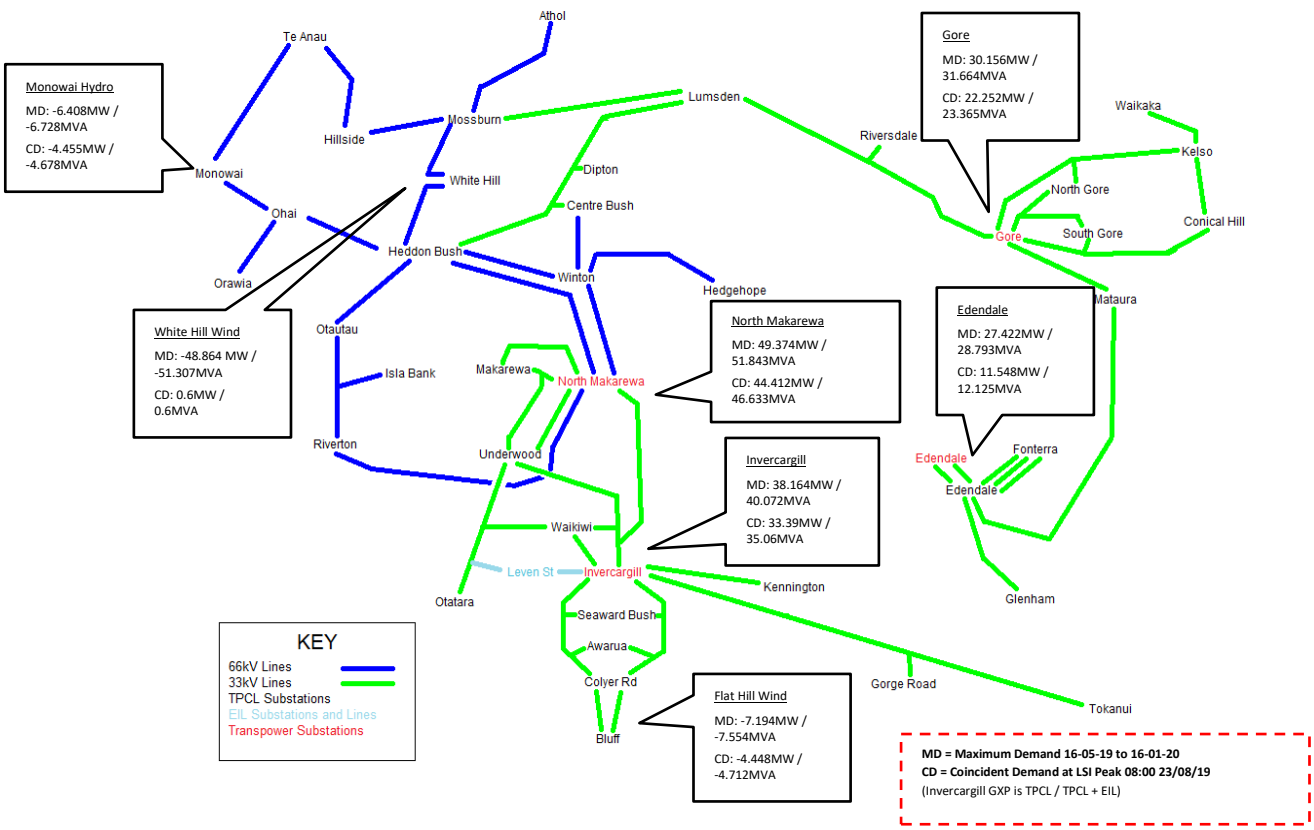


Figure 39: GXP and Generation Demands

Demand History and Trend

Growth trends are difficult to establish as there is somewhat random variation on top of underlying growth. Generally the trend taken over the latest ten year period will be quite different year to year as the most recent years' data is included and data beyond ten years is excluded. This is again quite different to a 20 year trend. Longer term trends tend to "average" out the random variations but lose sight of recent changes to underlying growth. Some causes may be identified with hindsight but are typically difficult to predict, for example a drought initiating increasing irrigation load. Growth is plotted and trend lines over various time periods are considered along with known events effecting consumption patterns before arriving at a reasonable estimate of growth which can be used for forecasting future demand and consumption.

Figure 40 shows the overall TPCL data since 1964 and highlights the flattening out since the late '80s. Recent flattening of maximum demand has been affected by changes in Transpower's Transmission pricing methodology; these changes are not apparent in energy growth. The most recent years have seen an increase on yearly maximum demand readings.

Analysis of historic demand and energy usage over the last 10 years or so gives maximum demand growth of between 0.5-1% and energy consumption growth of about 1%. Maximum demand was especially flat during the period 2012 to 2017. With the completion of the OCD capacity upgrade, it is expected that a singular step increase (between 5 and 10%) will be recorded in the 2020/21 FY results. The overall effect of drivers of future demand mentioned in Drivers of Future Demand is not expected to significantly alter these growth trends in future years. Historically, TPCL has experienced an average annual demand growth of about 2.0% for the last 20 years. This growth has been distorted with

Transpower's introduction of TPM[13] where individual EDB peaks have been replaced by a regional grouping. This has allowed some relaxing of winter load control during the year due to the increased summer loading (due to increased dairy farming on TPCL network). Whilst the company expects this average rate not to continue and to influence the revenue aspects of TPCL's business, such as pricing, it must be acknowledged that actual demand growth at localised levels (which will influence costs) can vary anywhere from negative to highly positive. The following sections examine in detail the most significant drivers of the network demand over the next 10 to 15 years.

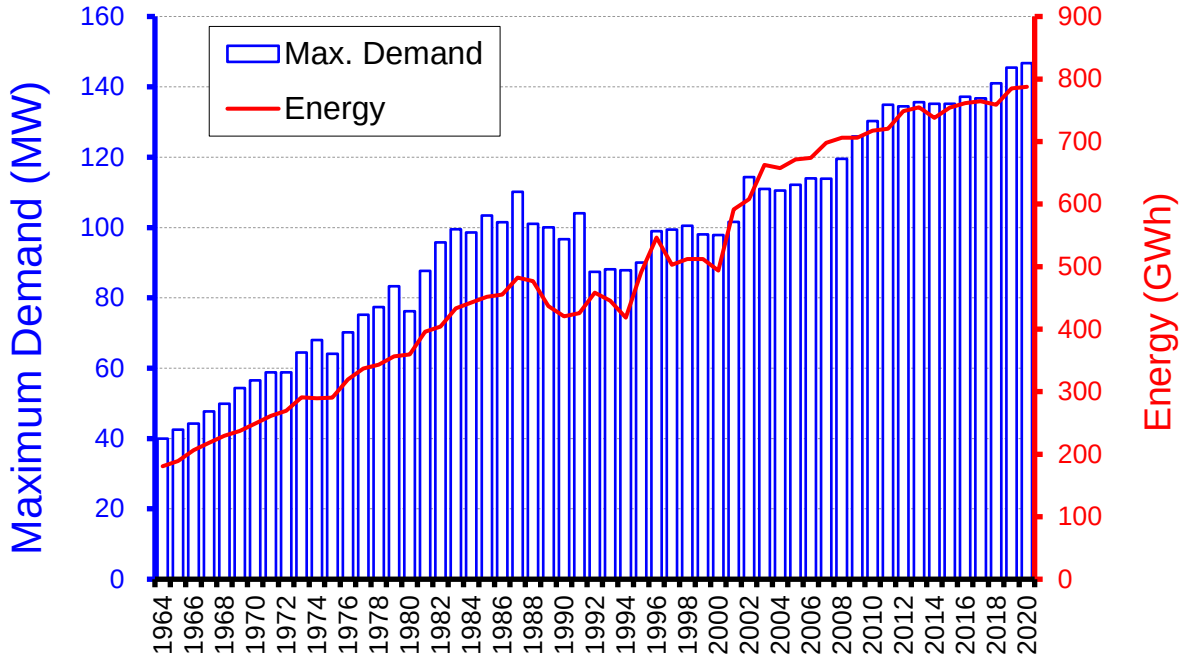


Figure 40: Maximum Demand and Energy Transmitted

Each zone substation recorded the maximum demands as listed in Table 35. The 99.9 percentile demand is given to remove any short term load transfers and is more indicative of actual area maximum demand.

[13] Transmission Pricing Methodology: Allocation of Transpower costs are based on the share of the average of the top 100 peaks for all loads in the Lower South Island (LSI) region.

Table 35: Substation Demand

Zone Substation	Firm Capacity (MVA)	Max Demand (MVA)	99.9 Percentile (MVA)					
		2019/20	2019/20	2018/19	2017/18	2016/17	2015/16	2014/15
Athol	5.0	1.16	0.89	0.9	2.09	2.02	2.27	0.61
Awarua Chip Mill	5.0	1.07	0.84	0.81	0.84	5.38	5.15	0.72
Bluff	12.0	6.43	5.17	5.36	4.7	4.70	4.69	4.32
Centre Bush	5.0	3.79	3.62	3.5	2.93	3.52	4.30	3.93
Colyer Road	12.0	7.60	7.41	7.16	7.08	6.63	4.66	-
Conical Hill	5.0	5.95	5.24	1.89	1.51	1.32	1.79	1.21
Dipton	1.5	1.47	1.32	1.54	1.19	1.94	1.77	1.74
Edendale Fonterra	46.0	26.01	24.62	24.64	28.78	26.24	21.28	23.35
Edendale	12	8.08	7.43	7.44	6.62	7.16	6.93	6.40
Glenham	1.5	1.43	1.22	1.26	1.24	1.29	1.46	1.54
Gorge Road	1.5	2.77	2.43	2.36	2.76	2.40	2.40	2.66
Hedgehope	5.0	1.69	1.57	1.59	1.50	1.65	1.65	-
Hillside	2.25	1.06	0.80	0.8	0.78	0.71	0.75	0.68
Isla Bank	5.0	1.92	1.87	1.99	1.78	1.99	-	-
Kelso	5.0	4.48	4.26	4.36	4.24	4.40	4.30	4.018
Kennington	12.0	7.15	6.82	6.06	6.06	5.38	6.45	5.88
Lumsden	5.0	3.41	3.24	3.24	3.63	3.72	3.38	3.20
Makarewa	12.0	4.45	4.30	4.19	4.18	4.59	5.31	6.30
Mataura	10.0	5.72	5.46	7.07	5.37	5.98	5.82	5.99
Monowai	1.0	0.13	0.13	0.13	0.16	0.15	0.13	0.16
Mossburn	3.0	2.32	2.11	2.51	2.67	2.27	2.37	1.96
North Gore	10.0	8.37	7.90	10.31	7.81	9.04	7.87	7.68
North Makarewa	45.0	33.57	31.45	43.66	46.05	42.14	44.17	45.70
Ohai	5.0	2.86	2.57	2.55	2.49	2.54	2.50	2.49
Orawia	5.0	3.23	3.06	3.09	3.0	3.40	3.11	2.99
Otatara	5.0	4.29	3.78	3.86	3.74	3.92	3.74	3.55
Otautau	7.5	3.71	3.37	3.32	4.04	4.57	4.37	4.11
Racecourse Road (EIL)	23.0	13.80	9.98	10.24	10.07	10.57	9.93	9.42
Riversdale	5.0	5.13	4.94	4.82	5.02	5.37	5.57	5.04
Riverton	7.5	5.14	4.91	4.73	4.29	4.23	4.21	4.55
Seaward Bush	10.0	8.30	7.64	7.01	6.51	7.61	7.98	8.03
South Gore	12.0	11.47	10.60	10.01	7.58	8.33	7.88	8.07
Te Anau	12.0	8.27	6.53	6.27	7.46	5.17	5.38	5.16
Tokanui	1.5	1.32	1.22	1.13	1.10	1.22	1.11	1.06
Underwood	20.0	12.30	10.96	11.19	11.89	12.00	11.80	12.45
Waikaka	1.5	1.60	1.48	0.75	0.77	0.78	1.01	0.75
Waikiwi	23.0	11.47	10.96	11.23	8.68	9.93	10.56	10.03
Winton	12.0	11.17	10.01	10.45	11.67	13.13	11.77	11.80
White Hill (Wind)		-55.84	55.54	-46.45	-54.17	-56.74	-56.60	-56.81
Monowai (Hydro)		-6.49	8.50	-7.47	-6.29	-6.47	-6.44	-6.56

The large embedded wind generator at White Hill is not taken into account in demand forecasting for North Makarewa GXP and 33/66kV transformers. This is because the variable wind resource means that it may not be generating at the same time as peak load. The Monowai hydro generators generally operate a single generator (2.5MVA) as a minimum operation. This is taken into account in demand forecasting for North Makarewa GXP and 33/66kV transformers.

Drivers of Future Demand

Future demand is forecast by understanding historical trends, projecting these trends into the future and altering these projections by factors which cause deviation of demand away from the current trends.

Figure 41 shows population projections for TPCL's network area as estimated by Statistics New Zealand from 2013 Census data. As well as total population the group 65 years and older is shown highlighting the predicted significant aging of the population.

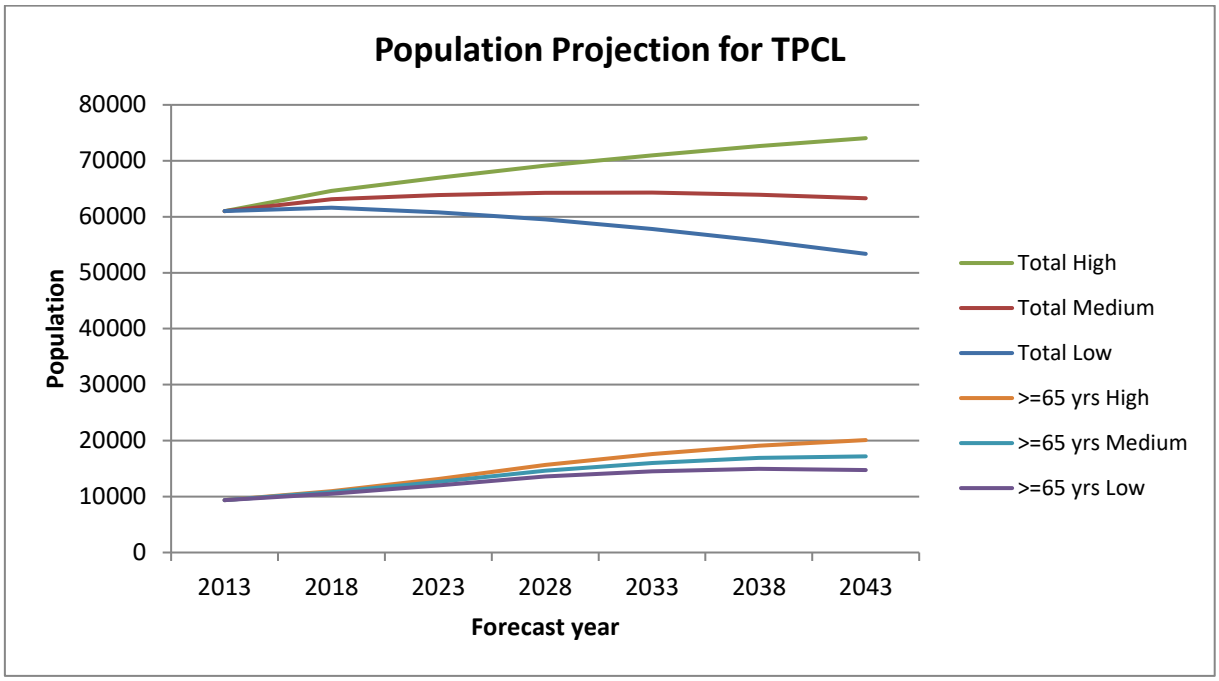


Figure 41: TPCL Population Projections

Table 36: Drivers of Future Demand

Demographics & Lifecycle	
Population Growth and Decline	**Effect:** Population projections indicates an initial static growth followed by average growth prospect of 2% between the periods 2018 to 2032.

Description: The population of TPCL's distribution area is approximately 61,000 as per last confirmed Census 2013 data. Census population projections[14] for TPCL's distribution area are shown in Figure 41. The high projection shows population increasing by 16% by 2032, medium projection increasing by 5%, and low projection showing a -5%% decline out to 2032.

The Southland District 10 year plan projects population to increase to 32,992 by 2028. Invercargill City population is projected to be approximately 56,300 by 2028. It is expected that the vast majority of growth would occur in urban areas of which Invercargill is Southland's largest metropolitan area. Further, Southland Institute of Technology as a tertiary education provider is seen as an important attractor for potential migrants located within central Invercargill.

Invercargill would attract the majority of potential migrants however the Invercargill area is supplied by both EIL and TPCL. TPCL supplies the outer regions of the city and as such expansion of Invercargill for additional housing would therefore often likely fall within TPCL's network boundary. EIL does have some undeveloped land suitable for housing and there is further potential for in-build with subdivided sections which if increased demand eventuates would be utilised to some extent. The increase in population numbers are more prevalent in areas supplied by North Makarewa and Invercargill GXP's.

[14] No updated population data available from last AMP

Demographics & Lifecycle	
Business expansion is also a target for the Southland Regional Development Plan and the majority of industrial expansion would expect to be within TPCL's network area.	
Housing Density and Utilisation	**Effect:** Housing density increases allow and are expected to create growth in TPCL's domestic supply demand. Increasing utilisation (more people per household) has the opposite effect
Description: Housing density can be expected to increase to some degree as the population increases. The trend for low care properties especially with an aging population is expected to continue while at the same time in-build is expected to continue as property owners subdivide in line with this demand. Expansion into new subdivisions at the edge of Invercargill would see growth on TPCL's network. The gradual trend toward smaller family size is expected to continue and this may counteract some of the growth caused by increased density	
Rural Migration to Urban Areas	**Effect:** Especially retirees (baby boomers)
Description: Urbanisation is a trend seen worldwide with rural people migrating into metropolitan areas and this trend has been seen in Southland also. Farming has been shedding jobs for some time as improved technology means fewer people are required per unit of production. This supports the above assumption that Southland's urban areas, particularly Invercargill, are likely to see the vast majority of population growth if the population growth strategy is successful. Figure 41 shows the number of people 65 years and older is projected to increase from about 15% to between 20% and 25% in 2028. The impact of farmers retiring to urban areas increases demand for townhouses in desirable locations. This is not a new effect and therefore there is no increase in growth expected above trending of previous years.	
Increasing Energy use per Customer	**Effect:** Growth minimal and included in existing demand trends.
Description: The use of heat pumps as air conditioners is becoming more common especially in commercial buildings. However this effect would improve load factor rather than increase peak demand as it occurs in summer while peak demand is driven by heating which occurs over the winter months. Further work is being done to understand if there is an increasing trend due to heat pumps. Consumer goods including appliances and electronic technology are generally becoming more affordable however while the numbers of these goods per household may be increasing they are often not used at the same time. Energy efficiency is also improving for many of these items offsetting any increases in household demand.	
Convenience of Electrical Heating	**Effect:** The effect of heat pump conversion is expected to be small, estimated to be about 0.5% growth in demand for TPCL over the next ten years. Incorporates growth anticipated from table 36; Council Fuel Burner Constraints.
Description: Electrical heating is generally the most convenient form of heating being available at the flick of a switch. Around 8% of energy consumption comes from gas and solid fuel based space heating and has the potential to be replaced by electrical heating. There is a trend of conversion to and greater reliance on electrical heating due to convenience and low running costs of electrical heating when using heat pumps. Heat pump installation cost is a barrier for many people and some prefer the ambience of other heat sources. Therefore complete conversion to electrical heating cannot be expected and further conversions will occur over an extended period of time. The additional demand that arises will be partly offset by increased use of heat pumps over other traditional electric heaters which can use three to four times the power to run.	
Electricity Affordability	**Effect:** Reduction of customer numbers and load
Description: Line charges in the Southland regions reflect TPCL's high cost of transporting energy over large distances to limited numbers of customers. These costs make alternative technologies such as solar and photovoltaic more attractive to customers. While these alternative technologies are not yet competitive with traditional supply, their gradually declining costs may make them more competitive toward the end of the planning period.	
Irrigation & Dairy	**Effect:** Accelerated growth for dairy conversions in pastoral areas of Southland and additional irrigation in the Northern Southland region

Demographics & Lifecycle
Description: Irrigation is becoming more common in the drier climate of Northern Southland. TPCL substations most likely to be affected are Dipton, Lumsden, Riversdale, Mossburn and Athol. Environment Southland has placed more stringent restrictions on the use of water which encourage the use of spray irrigators; which are both more water-efficient and more electrically demanding than the pre-existing irrigation schemes. The load growth can be very erratic as it depends very much on the effect of climate change and resulting harsh weather conditions outside the norm. The Ministry of Primary Industries has also placed more stringent requirements on the chilling of milk on dairy farms, which is expected to increase load in areas with a substantial dairy population. This affects most of TPCL's rural zone substations.

Table 37: Drivers of Future Demand

Environment and Climate	
Removal of Coal as Heating	**Effect:** Continuation of existing trends towards electrical space heating
Description: Regulations within the National Environmental Standards for air quality along with council fuel burner constraints will result in an increase in use of alternative sources of heating including heat pumps with resulting growth expected to affect residential areas. Heat pump usage has naturally continued to increase as a convenient and efficient form of heating and the impact on demand has been less than earlier anticipated, therefore existing growth has been assumed to continue.	
Council Fuel Burner Constraints	**Effect:** Continuation of existing trends towards electrical space heating

Description: Proposed updates to the Regional Air Quality Plan have been advised and include prohibition of open fires from 1 January 2017 in the Invercargill and Gore airshed areas. Further prohibition of non-approved burner/boilers in the Invercargill and Gore airshed areas occurs from the following dates;

Burner installation date	Prohibition date
Before 1 January 1997	Invercargill – 1 January 2019 Gore – 1 January 2020 Burn wood only from 1 January 2020
1 January 1997 – 1 January 2001	1 January 2022
1 January 2001 – 1 September 2005	1 January 2025
1 September 2005 – 1 January 2010	1 January 2030
1 January 2010 – 6 September 2014	1 January 2034

Approved boilers and burners are those which meet the national environmental Standards for emissions and thermal efficiency. Any burners installed after September 2005 may be on the Ministry of the Environment's list of approved burners and not require replacement. This phase-out of inefficient heating will require replacement and some degree of conversion to electrical heating with heat pumps is to be expected.

Energy Conservation Initiatives	**Effect:** Customers are responding to marketing, strategies and the availability of energy efficient products to reduce their consumption. Considered a significant driver of demand contraction however is mostly recognised within existing trends. Energy savings are likely to increase to some degree estimated at 0.5% (demand contraction) over the next ten years.

Description: Energy efficiency in consumer appliances is increasingly popular due the combination of government or local council drivers, marketing and consumer demand. Replacement of appliances with improved energy efficiency provides customers with the same benefits or standard of living while requiring less power consumed and so reduces power bills. Similar drivers are contributing to further installations of insulation which also assists in reduced power requirements for heating (see above section Energy Efficiency).

Increasing Ambient Temperature	**Effect:** Small increase in maximum demand on inland rural substations

Description: Increasing ambient temperature predicted by climate scientists may create increased demand for cooling and irrigation systems. This increased consumption would occur in the warmer months and therefore coincide with the peak demand in inland rural substations. In areas where the winter heating load dominates, increased cooling loads in summer months may improve load factor by a small degree.	
Wider Range in Weather Variations	**Effect:** Potential impact on maximum demand, and worsening load factor. Some impact on network reliability.
Description: Climate scientists forecast a potential for increasing frequency and/or intensity of storms, along with wider variations in seasonal weather. Colder periods may increase heating load, adding to winter peak demand.	

Table 38: Drivers of Future Demand

Economy	
Major Industry Continuance or Growth	**Effect:** Assumption that existing industries will continue and major new industries will eventuate
Description: Tiwai aluminium smelter takes supply directly from the transmission grid. However it helps support many businesses and individuals both directly and indirectly and loss of this business could have a major impact on the local economy and therefore growth on TPCL's network particularly in the Invercargill area. Negotiations between Rio Tinto and other stakeholders have resulted an agreement resulting in the continuation of operations at Tiwai smelter for a period up to three years. It is considered most likely Tiwai will continue to operate unchanged in the short term at least and therefore no change to growth forecasts has been made. A medium to long term view is more difficult to predict and will be assessed as future developments unfold. The Great Southern Basin is a potentially viable location for deep water oil drilling. Possible flow on effects if a deposit is developed could create infrastructure and demand at the Bluff port. However Dunedin port could be favoured over Bluff. The likelihood and level of growth from this effect is quite uncertain and has therefore not been included in forecasted growth.	
$NZD variation & commodity cycles	**Effect:** The improving economy will support the growth initiatives discussed in population growth and lifestyle.
Description: Economic downturn and recovery affects investment by customers and therefore the rate of growth. The global financial crisis affected the rate of growth causing a temporary stalling of new connections. A gradual recovery with growth increasing slowly has been evident.	

Table 39: Drivers of Future Demand

Technology	
Electric Vehicles	**Effect:** Negligible over planning period
Description: With significant penetration into the transport sector, electric vehicles have the potential to have a large impact on network demand. Some demand increase is expected in the second half of the planning period as electric vehicle adoption rates increase between 2% and 4% of the light passenger fleet by 2031. It is expected that the majority of this load should be able to be managed so that it is consumed at off-peak times (especially overnight) and therefore would have much less impact on peak demand and even improve load factor. There is likely to be some low peak demand growth but the impact will largely be felt in suburban LV networks in built up urban and semi-urban areas. The upstream MV network generally has sufficient capacity to support the expected growth from electric vehicles (estimated at 0.2% to 0.3% per annum from 2025/26). PowerNet is working towards a methodology to cluster smart meter profiles and some typical profiles that represents various customer segments on the network. PowerNet is currently simulating all ICPs without smart meters, to provide typical profiles. ICP's can then be grouped accordingly and future load projection can be simulated, incorporating other distributed energy resources (DER) such as photovoltaics (PV) and electric vehicle supply equipment (EVSE) or more commonly known as electric vehicle charging stations.	

Technology	
Autonomous Vehicles	**Effect:** Potential for residential customer density to spread. Potential clustering of electric vehicle charging during business hours, and greater loading on lines further from zone substations. Some impact expected toward the end of the ten year planning period.

Description: Autonomous vehicles have the potential to have a large impact on the spread of network demand if there is regulatory acceptance and sufficient penetration into the passenger transport sector.

Autonomous vehicles lower the costs of commuting, and may make living further from centres of business more viable for consumers. The economic case for uptake is further weighted by higher housing costs in target destinations.

Adoption and network impact is highly correlated to uptake of electric vehicles, as the technology is often packaged into newer electric vehicles. Housing cost drivers are viewed as less urgent in Southland, compared to other areas of New Zealand. So the impact of this technology on network demand is expected to be less rapid.

Distributed Generation	**Effect:** Generation tends not to coincide with network peak demand therefore the effect on network peak demand is expected to be negligible. However injection of generation during the period of low load around midday could potentially create voltage issues toward the end of the ten year planning period.

Description: The vast majority of the distributed generation seen so far has been solar installations and this trend is expected to continue for the foreseeable future. Relatively low numbers of new solar connections have been seen on TPCL's network to date. Although reducing costs are increasing the number of households for which a solar installation is cost-neutral, the majority of such customers either cannot afford a solar installation, are unable to install solar (e.g. rental), or prefer to dispose of their income elsewhere.

Public awareness of the environmental disadvantages of solar power is gradually increasing. Recent customer surveys indicate that more customers are considering purchasing solar in the medium term than any of the other disruptive technologies, most likely due to the influence of solar marketing efforts in recent years; but with energy cost reduction options such as home insulation and electric vehicles now also receiving increased marketing and generally offering a superior return, solar penetration is not expected to be widespread by the end of the planning period.

The LV network can however be vulnerable to solar installations; solar tends to depress the midday trough in demand (or even reverse power flow) whilst leaving the evening peak unaffected. This increases the range of load currents (and therefore voltage drops) under which the LV network must operate. A network tuned to deliver the minimum acceptable voltage in the evening may still exceed the maximum acceptable voltage at midday, if sufficient solar generation is connected. In weaker areas of the network a relatively small cluster of solar may be sufficient to cause issues.

The impact of solar installations on the network can be significantly reduced when the solar inverters employ volt-var compensation. The standard for new solar installations do require the usage of approved inverters capable of volt-var compensation. Similarly to electric vehicles, the concentration of effects on the LV network makes the location of future voltage problems difficult to predict. Individual ICP smart meter data will better enable TPCL to identify and address vulnerable points on the network.

Total energy consumption is likely to be reduced to some extent by solar installations within the planning period, however energy does not tend effect planning which focuses on providing capacity for peak demand periods.

Energy Storage	**Effect:** Not expected to be economic for customers within the ten year planning horizon and therefore negligible effect on network demand.

Description: Energy storage is one technology that could have a large impact on network demand especially if used in combination with distributed generation installations. Storage gives customers some control over their demand without impacting on their consumption, and could make it feasible for customers to go "off-grid" with a sufficiently sized solar system or other generation source. However there is significant uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to promote/utilise/market storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

Under the status quo this technology is not economic except in exceptional circumstances, and it is not expected that there will be major developments in this area for the next five years. If any such developments occur in the second half of the planning period, it is expected that they will take several years to have an

Technology	
impact at the network level, during which time TPCL can respond in a focused manner. Any impact these devices have is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets.	
Energy Efficiency	**Effect:** Negative growth driver accounted a part of the above discussed driver Energy conservation initiatives.
Description: Improving energy efficiency has been a government strategy for several years as discussed in Table 37 - Energy Conservation Initiatives. It is also desired by customers as a means of keeping their power bills down. More efficient appliances, lighting and heating are being developed to meet this demand. Other initiatives such as subsidies for home insulation are also helping customers to use energy more efficiently.	
On-line shopping	**Effect:** Likely to negatively affect the business sector in TPCL's network area however the overall effect on demand is expected to be relatively insignificant.
Description: Shopping online continues to become more and more popular with these online shops tending to be based out of the larger centres. This in turn means less demand for retail businesses within TPCL's network area. However there is also some opportunity for local businesses to connect with customers outside of Invercargill or even worldwide and this will somewhat offset the potential loss of business. It is expected the overall effect will be a loss for the business sector in TPCL's area.	
Internet of Things	**Effect:** It is not considered likely that this technology will be extensively used in the near future and has therefore not affected demand forecasts. In the case that it does eventuate in the next ten years the uptake of this technology is likely to be gradual and so plans would be able to react sufficiently quickly.
Description: The internet of things refers to the interconnection of the internet and many electronic enabled devices. In particular smart appliances may enable centrally controlled management of a dwelling's or business's consumption so that maximum demand may be minimised by staggering load to make the most of potential load diversity. This could enable customers to reduce line charges in line with a reduced network capacity requirement for their supply.	
Voltage support	**Effect:** Where there is a low voltage issue at the end of a feeder, an alternative approach to a traditional conductor upgrade, regulator installation or the supply voltage being increased, is the installation of capacitors or a Static VAr Generator.
Description: In cases where the load will increase on a feeder to the extent that the voltage will fall below the required levels there may be very significant costs associated with the implementation of a conductor upgrade, regulator installation or voltage upgrade. If this is the case and where the additional load is seen to be a one off or where there is seen to be a period of time where the load is not likely to increase significantly over the following few years, then the installation of voltage support may be the solution. They essentially defer the need for a more expensive solution. One strong factor in favour of technologies such as this is that if capacitors or a static VAr generator were to be installed, they could be redeployed to some other site if and when the load continues to increase. So they will never become a stranded asset.	

Response to Technology Impacts

The confluence of the various drivers, outlined above, is expected to change markets, regulations, and consumer behaviour. These changes create opportunities, as well as complexities and risks for TPCL.

TPCL is currently responding to these potential impacts by:

- Implementing more detailed demand data monitoring and analysis
- Increasing cross-industry collaboration
- Trialling new technology to better understand potential adoption and impact
- Continue improving dialogue with customers

- More cost reflective pricing (including Time-Of-Use). Introduction of a TOU pricing component is planned for 2021 but is dependent on Government phasing out the Low Fixed Charge.

TPCL is considering the following potential responses:

- Demand side management
- Partnerships for non-traditional solutions

However, if the extent of changes are sufficiently material, there is potential for assets to become underutilised such that TPCL may be unable to fully recover regulated investments.

There is some perceived risk of asset stranding for TPCL, and this is most likely to be in remote rural areas which have low customer density. However, the timing and extent of any asset stranding is linked to adoption rates of off-grid enabling technologies by consumers. As such this area of risk will continue to be monitored by TPCL.

Demand Forecasts

The overall impact of the drivers explained above is a slow growth rate for maximum demand on TPCL's network of 0.5-1.5% per annum. TPCL's total maximum demand is forecast to increase from approximately 146MW in 2019/20 to about 178MW in 2030/31. TPCL's demand (at a zone substation level) is expected to increase over the planning period by the following factors

- Standard natural growth of 1.0%, with some decline of small rural communities.
- Irrigation growth in Northern Southland of 1.5%.
- Tourism related growth in Te Anau of 1.5%, after short term peak demand decline before returning to positive growth.
- Continued Dairy conversions across pastoral Southland of 0.5%, with related growth at Edendale Fonterra of 0.25% and Colyer Road of 1.5%.
- Electric vehicle related growth of 0.3% from 2025.

Load Management shedding to control regional and local peaks is estimated at existing levels. The amount of this may decrease if price incentives are not passed on by retailers, or taken up by customers. Table 40 shows this growth on a per substation basis as the most appropriate network level for identifying constraints on the network.

Table 40: Existing Substations Growth Projection

Zone Substation	Proposed Annual Growth	Maximum Demand									
		2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Athol	2.50%	1.46	1.69	2.03	2.39	2.75	3.11	3.49	3.88	4.28	4.68
Awarua Chip Mill	0.00%	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09
Bluff	1.50%	5.63	5.72	5.80	5.89	5.98	6.07	6.16	6.25	6.35	6.44
Centre Bush	1.00%	4.10	4.14	4.19	4.23	4.27	4.31	4.35	4.40	4.44	4.49
Colyer Road	1.50%	9.88	10.03	10.18	10.33	10.49	10.64	10.80	10.97	11.13	11.30
Conical Hill	1.00%	3.55	3.59	3.62	3.66	3.70	3.73	3.77	3.81	3.85	3.89
Dipton	1.00%	1.36	1.37	1.38	1.40	1.41	1.42	1.44	1.45	1.47	1.48
Edendale Fonterra	0.50%	29.25	29.40	29.54	29.69	29.84	29.99	30.14	35.29	40.46	45.67
Edendale	1.00%	6.73	6.80	6.87	6.93	7.00	7.07	7.14	7.22	7.29	7.36
Glenham	1.00%	1.57	1.58	1.60	1.61	1.63	1.65	1.66	1.68	1.70	1.71
Gorge Road	1.00%	3.63	3.67	3.71	3.74	3.78	3.82	3.86	3.89	3.93	3.97
Hedgehope	0.5%	1.66	1.66	1.67	1.68	1.69	1.70	1.71	1.72	1.72	1.73
Hillside	1.00%	0.91	0.92	0.93	0.94	0.95	0.96	0.97	0.98	0.99	1.00
Isla Bank	1.00%	2.42	2.44	2.47	2.49	2.52	2.54	2.57	2.60	2.62	2.65
Kelso	0.5%	4.51	4.53	4.55	4.58	4.60	4.62	4.64	4.67	4.69	4.71
Kennington	1.50%	8.25	9.37	9.51	9.66	9.80	9.95	10.10	10.25	10.40	10.56
Lumsden	2.00%	4.17	4.23	4.29	4.36	4.42	4.49	4.56	4.62	4.69	4.76
Makarewa	0.50%	4.34	4.36	4.38	4.40	4.42	4.45	4.47	4.49	4.51	4.53
Mataura	0.50%	7.01	7.05	7.08	7.12	7.15	7.19	7.23	7.26	7.30	7.34
Monowai	0.50%	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.37	0.37	0.37
Mossburn	0.5%	1.85	1.86	1.87	1.87	1.88	1.89	1.90	1.91	1.92	1.93
North Gore	1.00%	10.17	10.27	10.37	10.48	10.58	10.69	10.80	10.90	11.01	11.12
Ohai	1.00%	2.69	2.71	2.74	2.77	2.80	2.82	2.85	2.88	2.91	2.94
Orawia	1.00%	3.24	3.27	3.30	3.34	3.37	3.40	3.44	3.47	3.51	3.54
Otatara	1.00%	4.26	4.30	4.34	4.39	4.43	4.47	4.52	4.56	4.61	4.66
Otautau	1.00%	4.18	4.22	4.27	4.31	4.35	4.40	4.44	4.48	4.53	4.57
Riversdale	2.50%	5.69	5.88	6.13	6.28	6.44	6.60	6.77	6.94	7.11	7.29
Riverton	1.50%	5.46	5.54	5.62	5.71	5.79	5.88	5.97	6.06	6.15	6.24
Seaward Bush	0.50%	7.83	7.86	7.90	7.94	7.98	8.02	8.06	8.10	8.14	8.18
South Gore	1.50%	10.91	11.07	11.24	11.41	11.58	11.75	11.93	12.11	12.29	12.47
Te Anau	2.00%	6.52	6.52	6.52	6.66	6.79	6.92	7.06	7.20	7.35	7.49
Tokanui	1.00%	1.35	1.37	1.39	1.41	1.43	1.45	1.47	1.49	1.52	1.54
Underwood	0.00%	11.02	11.02	11.02	11.03	11.03	11.03	11.04	11.04	11.04	11.05
Waikaka	1.50%	0.85	0.86	0.87	0.87	0.88	0.89	0.90	0.91	0.92	0.93
Waikiwi	1.50%	12.95	13.15	13.34	13.54	13.75	13.95	14.16	14.37	14.59	14.81
Winton	1.00%	11.36	11.47	11.59	11.70	11.82	11.94	12.06	12.18	12.30	12.42
White Hill (Wind)	0.0%	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76	54.76
Monowai (Hydro)	0.0%	-6.41	-6.41	-6.41	-6.41	-6.41	-6.41	-6.41	-6.41	-6.41	-6.41
Flat Hill (Wind)	0.0%	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19	-7.19

Athol, Centre Bush, Dipton, Lumsden, Riversdale and Mossburn are all located in Northern Southland region where continuous growth occurs for irrigation and dairy plants. In particular, Athol, Lumsden and Riversdale have shown continuous demand growth with Mossburn and Dipton indicating reduced growth over the past few years. The above substations all forms part of the greater 66kV supplied from North Makarewa GXP. While from the same GXP, the 33kV subtransmission network has lower growth prospects offsetting the overall maximum demand growth projections.

The completion of the Open Country Dairy upgrade have realised a considerable demand increase at both Colyer substation and the TPC demand at Invercargill GXP. Increased industrial activity within the Kennington substation zone, will result in an increased step demand within the next two years.

Riverton and Gorge Road indicated steady growth above 1%.

Waikiwi can vary significantly due to the predominantly residential load, a positive update have been recorded recently. Although the diversified maximum demand growth for residential customers are flat, seasonal variability do influence the overall demand recorded and influence large proportional domestic load profiles.

The impact of the CoVID-19 virus have had a negative impact on Te-Anau substation in particular. Peak demand recorded over the past 12 months have a shown a considerable reduction at Te-Anau substation, especially during the peak Easter and summer holiday periods. Typical tourist accommodation have been severely affected and some existing commercial ICP's have reduced their contracted capacity as a result. It is currently forecasted that demand will be stagnant in the immediate future with growth projected from 2024 onwards.

The overall impact of the drivers explained above is a slow growth rate for maximum demand on TPCL's network of 0.5-1.5% per annum. TPCL's total maximum demand is forecast to increase from about 147MW in 2019/20 to about 178MW in 2030/31. TPCL's demand (at a zone substation level) is expected to increase over the planning period by the following factors

- Standard natural growth of 1.0%, with some decline of small rural communities.
- Irrigation growth in Northern Southland of 2%.
- Tourism related growth in Te Anau is expected to be nominal within the short term, before returning to an expected growth projection of 1.5%.
- Continued Dairy conversions across pastoral Southland of 0.5%, with related growth at Edendale Fonterra of 0.5% and Colyer Road of 1.5%.
- Electric vehicle related growth of 0.2% from 2022.

Load Management shedding to control regional and local peaks is estimated at existing levels. The amount of this may decrease if price incentives are not passed on by retailers, or taken up by customers. Table 40 shows this growth on a per substation basis as the most appropriate network level for identifying constraints on the network.

These projected substation demands are considered the most likely outlook and are the basis for TPCL's network development planning. It is accepted that there is significant uncertainty in these forecasts and actual future demands may depart significantly from these levels. Forecasts are updated annually to ensure plans are able to react quickly to any changes from previous assumptions.

If growth rates decline, schedules for projects to address capacity constraints are correspondingly delayed so as to minimise the risk of over investing. Ultimately TPCL seeks to realise growth opportunities as they arise which means developing the network to alleviate constraints as required accepting, as with any investment that some risk is involved. Risk of stranding of new assets is managed where appropriate through capacity guarantee contracts with new customers. Otherwise risk is minimised by avoiding investment by utilising whatever options are available to defer investment until absolutely necessary while maintaining desired service levels.

Higher growth rates are also possible and present a risk of missed opportunity for growth for both TPCL and TPCL's customers. Growth affecting the entire network is most likely to come with sufficient

warning to allow resources to be adjusted as required. Any large scale developments are likely to be largely funded by external investors through capital contributions and TPCL generally has the ability to respond quickly to unforeseen large scale one off developments. Naturally there are limits to this capability and negotiation may be required around timing of project delivery. Unfortunately experience shows that while endeavours are made to warn customers of potential lead times around providing additional network capacity, requests for supply tend to come relatively late in their planning processes due to commercial sensitivities.

Table 41 shows the aggregated effect of substation demand growth for a 10 year horizon at the four GXPs which provide supply TPCL.

Table 41: GXP Demand Growth

GXP	Rate and nature of growth	Provision for growth to 2026
Invercargill	1% Maximum Demand Load allocated towards TPC load from Invercargill GXP. Strong growth from commercial customers at Colyer and Kennington substations.	Transpower have adequate firm capacity (120MVA) at the Invercargill GXP.
North Makarewa	1% Increased load from irrigation in Northern Southland and continued dairy growth across Northern and Western Southland.	Load forecast is under firm capacity of 67MVA. Any substantial embedded generation is likely to make this a normally exporting GXP, Possible Transpower project to allow 76.1/79.4 MVA (summer/winter) capacity with 33kV cable upgrade.
Gore	0.5% Increased load from continued dairy growth across Eastern Southland.	Load is under firm capacity of 36.6/37.9 MVA (summer/winter) and load control will be used to keep under this limit. Mataura is able to be transferred onto Edendale GXP during Dairy off-season. Any major new loads will require additional capacity at Transpower or an agreement to drop new load if Transpower loses one supply transformer.
Edendale	0.25% Growth from Fonterra Edendale and TPCL Edendale and Glenham substations.	Current forecast shows approaching of summer capacity of 34MVA during planning period. Discussions have begun with Transpower to look at project to allow full 36.6/38.7 MVA (summer/winter) capacity and future long term upgrade. .

Constraints Arising from Estimated Demand

The significant issues arising from the estimated demand are the capacity at a number of zone substations. Most of these are covered by upgrade projects which are discussed in full in section Development Programme.

A summary of TPCL's network constraints is shown in Table 42:

Table 42: TPCL Network Constraints and Intended Remedy

Constraint	Description	Intended remedy
Capacity at Zone Substations	Substations close to (or exceeding) maximum capacity. Glenham, Kelso, North Gore, Tokanui, Riversdale, South Gore, Winton	Load are reviewed annually to ensure timing of projects is kept just ahead of load. Upgrades planned for, Glenham, Kelso, and Riversdale during the planning period. Load transfers will be used to keep, North & South Gore, Tokanui plus Winton under their respective capacity.
Gore GXP	Close to firm capacity of 36.6/37.9 MVA (Summer/Winter)	Up-size when load control cannot keep load under this limit.
North Makarewa GXP	Firm capacity 62.3MVA, limited by 33kV cable and protection	Transpower project to upgrade cables and protection to allow 76.1/79.4MVA. Up-size when load control cannot keep load under this limit. Close monitoring of the 66kV load within firm capacity.
Subdivisions	Possible large developments in Athol and Kingston	Upgrade MV distribution network to 22kV from Athol substation. Extend 66kV subtransmission to Kingston if further growth occurs
Environmental – Oil	Expectation that no significant oil spills from substations	Install oil bunding, blocking and separation systems.
Limited 66kV transfer capability between Gore and North Makarewa GXP's	Limited integration between Gore and North Makarewa GXP.	Investigate network upgrades to improve network reliability during contingency conditions
11kV voltage low due to Dairy milking	Conversion of farms to dairying may cause feeder voltage to drop below 0.94pu.	Install 11kV regulators to improve voltage. Install new substations or convert lines and supply to 22kV if growth continues.
Irrigation Plants	Abnormal and dry weather conditions will impact demand on inland areas causing voltage drop below 0.94p.u.	Upgrade networks as required to support voltage constraints.
Coastal marine	Salt pollution reducing insulation effectiveness. Increased corrosion.	Over insulate lines. Use high pollution type equipment. Enclose substation equipment inside buildings. Increased renewals of outdoor equipment.
MV Transformers	Some transformers are near full capacity.	Maximum Demand Indicators (MDIs) are monitored and transformers will be upsized or supplemented with additional units as appropriate. Underutilised transformers may be relocated before purchasing new.

Table 43 and Table 44 show the substation demands and proposed changes to keep demand within the capacity of zone substations. Proposed changes show new substations, upgrades to existing substations, and load transfers to and from substations to maintain capacity ahead of demand. New substations and upgrades to existing substations are discussed fully in section Development Programme

Table 43: Substation Demands with Proposed Developments 2021 - 2026

Zone Substation	2020/21 Changes	2020/21 Demand	2021/22 Changes	2021/22 Demand	2022/23 Changes	2022/23 Demand	2023/24 Changes	2023/24 Demand	2024/25 Changes	2024/25 Demand	2054/26 Changes	2025/26 Demand
Athol		1.03		1.46		1.69		2.03		2.39		2.75
Awarua (Chip Mill)		2.09		2.09		2.09		2.09		2.09		2.09
Bluff		5.55		5.63		5.72		5.80		5.89		55.98
Centre Bush		4.06		4.10		4.14		4.19		4.23		4.27
Colyer Road		9.73		9.88		10.03		10.18		10.33		10.49
Conical Hill		3.52		3.55		3.59		3.62		3.66		3.70
Dipton		1.34		1.36		1.37		1.388		1.40		1.41
Edendale Fonterra		29.10		29.25		29.40		29.54		29.69		29.84
Edendale		6.66		6.73		6.80		6.87		6.93		7.00
Glenham		1.76		1.78		1.80		1.81		1.83	-1.85	1.85
Glenham (Upgraded)											+1.85	1.85
Gorge Road		3.60		3.63		3.67		3.71		3.74		3.78
Hedgehope		1.65		1.66		1.66		1.67		1.68		1.69
Hillside		0.9		0.91		0.92		0.93		0.94		0.95
Isla Bank		2.4		2.42		2.44		2.47		2.49		2.52
Kelso		4.48		4.51		4.53		4.55		4.58	-4.60	0.00
Kelso (Upgraded)											+4.60	4.60
Kennington		7.35		8.25		9.37		9.51		9.66		9.80
Lumsden		4.10		4.17		4.23		4.29		4.36		4.42
Makarewa		4.31		4.34		4.36		4.38		4.40		4.42
Mataura		6.98		7.01		7.05		7.08		7.12		7.15
Monowai		0.2		0.2		0.2		0.2		0.2		0.2
Mossburn		1.85		1.85		1.86		1.87		1.87		1.88
North Gore		10.07		10.17		10.27		10.37		10.48		10.58
North Makarewa		43.93		44.37		44.81		45.26		45.71		46.17
Ohai		2.66		2.69		2.71		2.74		2.77		2.80
Orawia		3.21		3.24		3.27		3.30		3.34		3.37
Otatara		4.22		4.26		4.30		4.34		4.39		4.43
Otautau		4.14		4.18		4.22		4.27		4.31		4.35
Riversdale		5.55		5.69		5.88		6.13	-6.28	6.28		0.00
Riversdale Upgraded									+6.28	6.28		6.44
Riverton		5.38		5.46		5.54		5.62		5.71		5.79
Seaward Bush		7.79		7.83		7.86		7.90		7.94		7.98
South Gore		10.75		10.91		11.07		11.24		11.41		11.58
Te Anau		6.52		6.52		6.52		6.52		6.66		6.79
Tokanui		1.33		1.35		1.37		1.39		1.41		1.43
Underwood		11.02		11.02		11.02		11.02		11.02		11.02
Waikaka		0.84		0.85		0.86		0.87		0.87		0.88
Waikiwi		12.76		12.95		13.15		13.34		13.54		13.75
Winton		11.25		11.36		11.47		11.59		11.70		11.82
White Hill (Wind)		-55.76		-55.76		-55.76		-55.76		-55.76		-55.76
Monowai (Hydro)		-6.41		-6.41		-6.41		-6.41		-6.41		-6.41
Flat Hill (Wind)		-7.22		-7.22		-7.22		-7.22		-7.22		-7.22

Table 44: Substation Demands with Proposed Developments 2027 – 2031

Zone Substation	*2026/27 Changes*	2026/27 Demand	*2027/28 Changes*	2027/28 Demand	*2028/29 Changes*	2028/29 Demand	*2029/30 Changes*	2029/30 Demand	*2030/31 Changes*	2030/31 Demand
Athol		3.11		3.49		3.88		4.28		4.68
Awarua (Chip Mill)		2.09		2.09		2.09		2.09		2.09
Bluff		6.07		6.16		6.25		6.35		6.44
Centre Bush		4.31		4.35		4.40		4.44		4.49
Colyer Road		1.64		10.80		10.97		11.13		11.30
Conical Hill		3.73		3.77		3.81		3.85		3.89
Dipton		1.42		1.44		1.45		1.47		1.48
Edendale Fonterra		29.99		30.14	-5.00					
Edendale Fonterra (Upgraded)					+5.00	35.29	+5.00	40.46	+5.00	45.67
Edendale		7.07		7.14		7.22		7.29		7.36
Glenham		0.00		0.00		0.00		0.00		0.00
Glenham (Upgraded)		1.87		1.89		1.91		1.93		1.94
Gorge Road		3.82		3.86		3.89		3.93		3.97
Hedgehope		1.70		1.71		1.72		1.72		1.73
Hillside		0.96		0.97		1.98		1.99		1.00
Isla Bank		2.54		2.57		2.60		2.62		2.65
Kelso		4.62		4.64		4.67		4.69		4.71
Kennington		9.95		10.10		10.25		10.40		10.56
Lumsden		4.49		4.56		4.62		4.69		4.76
Makarewa		4.45		4.47		4.49		4.51		4.53
Mataura		7.19		7.23		7.26		7.30		7.34
Monowai		0.20		0.20		0.21		0.21		0.21
Mossburn		1.89		1.90		1.91		1.92		1.93
North Gore		10.69		10.80		10.90		11.01		11.12
North Makarewa		46.63		47.10		57.57		48.04		48.52
Ohai		2.82		2.85		2.88		2.91		2.94
Orawia		3.40		3.44		3.47		3.51		3.54
Otatara		4.47		4.52		4.56		4.61		4.66
Otautau		4.40		4.44		4.48		4.53		4.57
Riversdale		0.00		0.00		0.00		0.00		0.00
Riversdale (Upgraded)		6.60		6.77		6.94		7.11		7.29
Riverton		5.88		5.97		6.06		6.15		6.24
Seaward Bush		8.02		8.06		8.10		8.14		8.18
South Gore		11.75		11.93		12.11		12.29		12.47
Te Anau		6.92		7.06		7.20		7.35		7.49
Tokanui		1.45		1.47		1.49		1.52		1.54
Underwood		11.03		11.03		11.03		11.03		11.03
Waikaka		0.89		0.90		0.91		0.92		0.93
Waikiwi		13.95		14.16		14.37		14.59		14.81
Winton		11.94		12.06		12.18		12.30		12.42
White Hill (Wind)		-55.76		-55.76		-55.76		-55.76		-55.76
Monowai (Hydro)		-6.41		-6.41		-6.41		-6.41		-6.41
Flat Hill (Wind)		-7.22		-7.22		-7.22		-7.22		-7.22

4.3. Development Programme

Riversdale 22kV Line Upgrades

There has been significant load growth in the Riversdale area. The bulk of the growth has come from increased irrigation in the vicinity of Waipounamu and Freshford. Recent irrigation load connection requests have been received which means that the existing 11kV network cannot deliver acceptable voltage. This growth has also eroded the 11kV backup capability between the Lumsden and Riversdale substations.

Transfer of load to a new substation around Balfour (which is approximately halfway between Riversdale and Lumsden) would alleviate the transformer capacity trigger and improve the 11kV backups between Riversdale and Lumsden. However, the new substation at Balfour would not provide a solution to the load growth being experienced north of Riversdale in the Waipounamu and Freshford areas and as such has been removed as a project.

It is proposed to upgrade the existing Riversdale substation in the short to medium term. The upgrade will include the establishment of 22kV at Riversdale. This will integrate with the long term distribution network including Lumsden. In preparation, sections of the Riversdale 3 feeder is being prepared for 22kV. An additional feeder is also to be installed splitting the Riversdale 3 and Riversdale 4 load more equally.

Cost $1,370M for 2021/22, $0.425M for 2022/23, $0.425M for 2023/24 and $0.437M 2024/25 – System Growth

22kV Upgrade Athol – Kingston

Load growth occurring in and around Kingston Township is forecast to exceed the ability of the 11kV network to supply adequate voltage. The new loads are mainly irrigation demand for the summer months and the proposed Kingston Village development which will consist of an approximate 700 residential units. The proposed implementation plan is to progressively upgrade the network until a new 66/11kV zone substation is required.

The proposal is to phase the upgrade as follows:

Phase 1 is to upgrade a portion of the ATH5 feeder from Squirrel and fox conductor to Iodene. The existing Fairlight regulator is to be replaced with a new dual voltage (22/11kV) unit at Garston. Two additional regulators are to be installed at Black bridge and Allandale respectively.

Phase 2 install a 500kVAr static VAr generator at Kingston

Phase 3 is to convert the AHL5 feeder from 11kV to 22kV. Minor alterations will be required at Athol substation and the AHL3 feeder will require a 22/11kV auto transformer to provide correct voltage interface with the separate voltages. The upgrade will include the re-insulation of the AHL5 feeder but some laterals will be kept at 11kV to limit costs. 22/11kV autotransformers will be installed at identified laterals. Due to access limitations on the existing AHL feeder from Athol, a new 22kV cable will be installed, connecting the Athol local load and being re-introduced in the existing AHL feeder at Black bridge. The conversion program will be done in a progressive manner as it is not possible to transfer all load onto alternative circuits to upgrade the AHL5 feeder.

Cost of $0.910M during 2021/22, $2,119M during 2022/23, $1,506M during 2023/24 and $2,309M during 2024/25; CAPEX – System Growth

Communications Projects

There are two main issues with the communications networks in TPCL area.

There has been very little in the way of equipment replacement or development over many years. It utilises thin route serial and time division multiplexing technology. Modern substation equipment has migrated to Internet Protocol based input and output systems. This requires an IP capable communications network. This will bring the ability to monitor protection relays remotely including the ability to obtain fault records and wave analysis to assist in the detection of faults.

Many of the existing communications links do not have backup paths.

These issues are planned to be addressed within the planning period. The first phase of the project is to create an alternative communication link between Invercargill and North Makarewa GXP. The first stage will be completed during 2020/21.

Cost $0.48M for 2021/22, and Under $0.4M for 2022/23 to 2030/31; CAPEX – Other Reliability

Substation Safety

Arc flash hazards have been identified around indoor MV switchgear at zone substations, presenting a risk of harm to personnel inside substation buildings, especially during operation of the switchgear.

The project will retrofit arc flash detection through the use of modern protection relays to all indoor switchboards. This will reduce the hazard for personnel to under the levels provided by 8cal/cm^2 overalls required to be worn by all staff when entering zone substations. Additional PPE (Personal Protection Equipment) was considered as an alternative, but was determined to be suboptimal as each employee would require a full 40cal/cm^2 suit and the bulky PPE to achieve this level of protection creates additional hazards for personnel.

Cost Under $0.3M per annum 2021/22 and 2022/23; CAPEX – Other Reliability, Safety and Environment

Remote Area Power Supplies

There are a number of remote spurs on the network which have very little load attached to extended lengths of overhead networks requiring high maintenance costs. At these locations there is an option to implement the usage of a Remote Area Power Supply. The remote supply will eliminate the requirement of the existing electrical circuit, thus eliminating excessive maintenance and refurbishment costs in future. Installations are site specific and installed to provide suitable capacity for current and future demand.

Cost under $0.3M from 2021/22 to 2023/24 and then continuous per year from 2026/27 to 2030/31; CAPEX - Other Reliability, Safety and Environment

Hillside Protection Remediation

There is no backup protection at Hillside substation. The existing network configuration also have limitations and require an upgrade to improve network sensitivity. This needs to be remedied in order to increase the safety and the equipment protection at this site.

Cost $0.369M in 2021/22; CAPEX - Other Reliability, Safety and Environment

Planned Projects (Years 2 – 5: 2022/23 – 2025/26)

Riversdale Substation Upgrade

Load growth has reached the capacity trigger point of 5MVA which aligns with the existing single 33/11kV 5MVA transformer.

Although load growth in recent years had been lower than expected, loading has increased in the last financial year. An analysis of the loading data shows that the 5MVA ONAN capacity of the transformer is only exceeded for short periods at peak times. Fans have been installed to accommodate an additional demand during these short periods. Following this analysis it has been determined that no action is required until the peak load exceeds 6MVA as the loading up until this point will remain within the overload capability of the transformer.

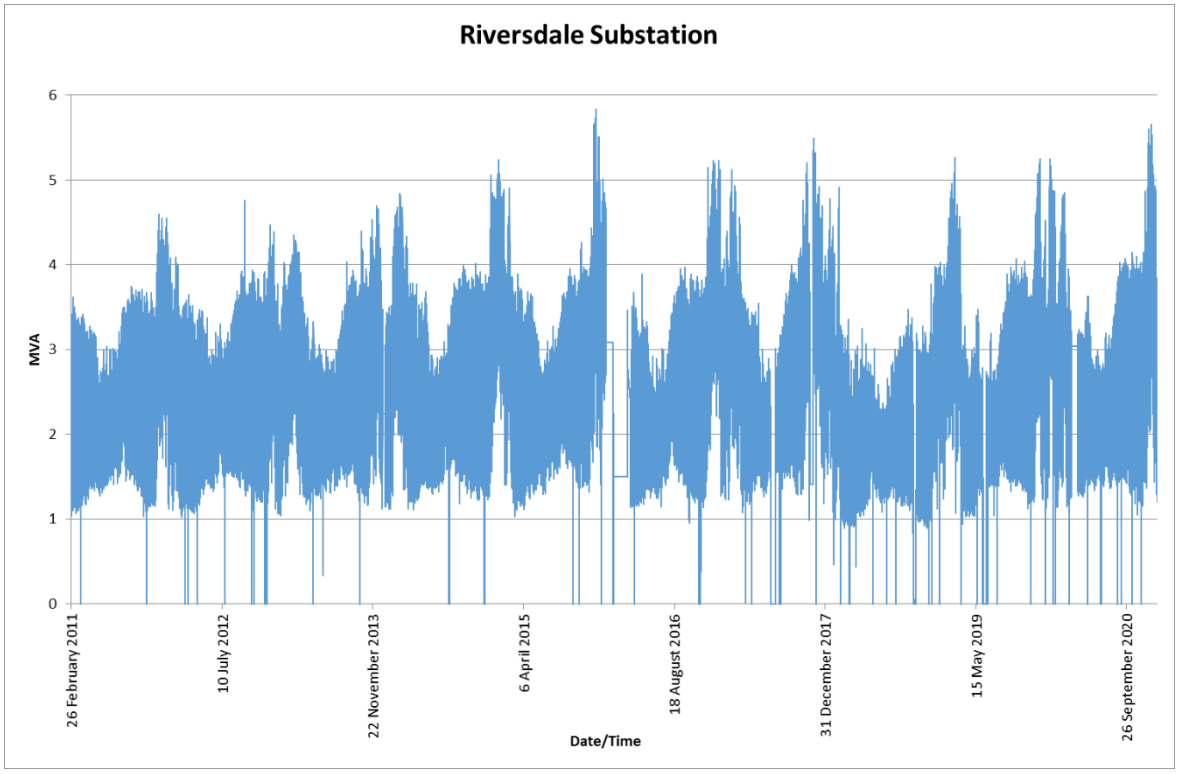


Figure 42 - Riversdale Substation Load Profile

Load transfer within the 11kv network has limited scope and if load growth occurs as projected at Riversdale, a substantial upgrade of the substation will be required. The proposed solution is to install a new 66/22kV, 6/12MVA transformer and 22kV indoor switchboard with four feeders, two incomers and a bus coupler. The new transformer would operate in parallel with the existing 33/11kV 5MVA unit. The new switchboard would have 2 feeders operating at 11kV and 2 feeders operating at 22kV with the bus coupler remaining open. Backup between the 2 transformers will be achieved by the use of 11/22kV autotransformers installed at tie-points between the 11kV and 22kV feeders. The bus-section breaker would be permanently locked racked out until the complete network is converted to 22kV. A diagram of the proposed solution is shown in figure 43.

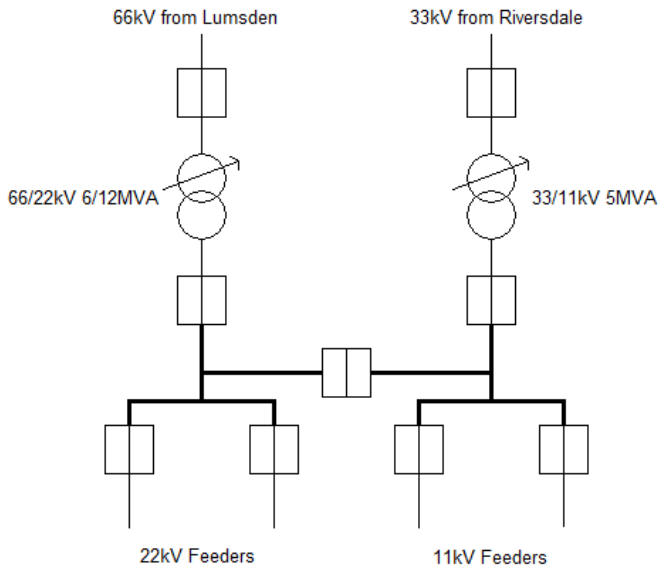


Figure 43 - Proposed Riversdale Single Line Diagram

Cost under $1,557M per annum 2023/24 to 2024/25; CAPEX - System Growth.

Kelso Transformer Upgrade

Load growth is forecast to exceed the 5MVA capacity of the transformer at Kelso Substation in the medium term. This project will add fans to the transformer to increase its capacity. This should provide for another 10 years of growth.

Consideration was given to load transfers, within the 11kV network, to keep load under 5MVA however backup capability on 11kV from neighbouring substations is limited by voltage drop so load transfer is not practical.

Further consideration was also given to adding a second transformer. However, this would require new switchgear and changes to the existing spare transformer pad. The security standard does not require two transformers and the mobile substation can be deployed to allow maintenance or upgrade. The installation of a second transformer was considered likely to be more expensive and not an efficient use of capital.

Cost $0,1M - $0,2M 2025/26; CAPEX - System Growth.

Glenham Transformer Upgrade

Load growth is forecast to exceed the nominal capacity of the transformer at Glenham Substation in 2022. If load growth continues, the project will be brought forward to 2022. The substation provides limited 11kV backup to the adjacent Gorge Road and Tokanui substations, it is proposed to replace the single 33/11kV 1.5MVA power transformer at Glenham substation with a new 33/11kV 3MVA transformer or refurbished 5MVA transformer.

Cost $1,411M 2025/26; CAPEX - System Growth.

Projects (Years 6 – 10: 2026/27 – 2030/31)

Unspecified Projects

The unspecified projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low.

The distribution network between North and South Gore is a meshed network with tie point changes reflecting on both substations load profiles. Load growth projections at both North and South Gore are being closely monitored. If growth continues as projected, the upgrade of capacity will be brought forward within the period. The two substations also play a key role in the Gore GXP demand profile.

$1.5M - $4M per annum 2025/26 onwards; CAPEX - System Growth

Condition Based asset replacements

Budget has been allocated to replace or renew assets not currently funded from the short term budget timeline. Through the improvement of fleet plans and asset condition assessments, individual programs will be implemented.

Under $6M from 2026/27 to 2031/31.

Routine / Ongoing Projects

Customer Connections + New Subdivisions

These budgets are for new connections to the network including subdivisions where a large number of customers may require connection. Each individual solution will depend on location and the customers' requirements.

The new connections budget uses averages based on historical trending, modified if there is any information available however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance.

Various options are considered generally to determine the least cost option for providing the new connection. The work required depends on the customer's location relative to the existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, to the installation of a new transformer site with associated 11kV extension if required. Even small customers can require a large investment to increase network capacity where existing capacity is already fully utilised.

Distributed generation as a network alternative tends to be intermittent so cannot be relied on without energy storage which may make an installation uneconomic. Some schemes may be becoming cost competitive with supply from the network however the upfront cost is generally not attractive to most customers and generally a connection to the network is still desired as backup, supplementation and sometimes the ability to sell surplus energy. Customers may be encouraged to better manage diversity of load within their facilities where details are known and there is a perceived benefit to the customer or the network owner.

Cost $3M in total over a number of budgets per annum on-going; CAPEX - Consumer Connections.

Line Relocation Projects

This budget captures costs for relocation works when requested by authorities or customers such as shifting a pole or pillar box to a more convenient location. Costs budgeted represent a long term average with actual spend being reactive and typically above or below budget in any year.

Cost Under $0.2M per annum on-going; CAPEX – Asset Relocations

Supply Quality Upgrades

This covers projects to remedy poor power quality. Most cases of poor power quality on TPCL's network are reports or measurements of low voltage. Voltage is either then measured (or calculated to vary) outside of regulatory limits.

Each of the below options / situations are considered and an appropriate solution implemented.

- Installation of 11kV regulators.
- Up-sizing of components (Conductor, Transformer).
- Demand side management. (Planning an Irrigation ripple control channel.)
- Power factor improvements. (Ensuring customer loads are operating effectively.)
- Harmonic filtering / blocking. (Ensuring customers are not injecting harmonics.)
- Motor starter faults / settings remedied. (Ensuring customer equipment is working and configured appropriately.)

Costs budgeted represent a long term average with actual spend being reactive typically being above or below in any year.

Cost under $0.5M per annum on-going; CAPEX – Quality of Supply.

Mobile Substation Site Made Ready

This project provides connection points for the mobile substation at single transformer substations. The aim is to have each substation suitably arranged to allow the mobile substation to be connected for either maintenance activities or to cover transformer or other major equipment failures. The works will vary at each substation but could include additional land, fencing, gravel, earthing, HV connection / isolation point, MV connection / isolation point.

Cost Under $0.3M alternate years 2022/23 & 2024/25; CAPEX – Quality of Supply

Network Improvement Projects

Projects to improve reliability through installation of remotely controlled field circuit breakers and load break switches or closing short gaps between adjacent 11kV circuits.

Cost Under $0.2M per annum on-going from 2020/21 while alternating between 2021/22 until 2025/26; CAPEX – Quality of Supply

Earth Upgrades

Ineffective earthing may create hazardous voltage on and around network equipment (Earth Potential Rise; EPR) during fault situations potentially affecting safety for the public and for staff. Poor earthing can also prevent protection systems from operating correctly, which may affect the safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades.

Determining the most appropriate upgrade option can be quite complex, but the ultimate aim is to find the optimal trade-off between cost and risk reduction. Upgrade works may include additional earthing rods or banks, replacement of surface material (asphalt or gravel) to reduce risk, and installation of insulating fences or fence sections to reduce the risk of transfer of voltage to adjacent conductive fences.

Routine testing is completed five yearly.

A number of sites have been identified for the required upgrading of the existing earthing system. Additional CAPEX have been allocated in the 2021/22 financial year to address the immediate need.

Cost under $3M from 2021/22 to 2024/25 then under $1.5M from 2025/26 to 2030/31; CAPEX – Other Reliability, Safety and Environment.

4.4. Contingent projects

The following projects are classified as contingent projects. They are contingent upon particular projects going ahead and further investigation. These have not been included in TPCL's spend plans as yet and will only do so if/when they become more certain.

Edendale Process Heat Electrification/ Transpower Edendale Transformer Upgrade

The Fonterra Edendale plant currently uses coal to provide the process heat. There is a proposal to replace coal as the energy source with either electricity or biomass. The Edendale factory is not likely to be the first plant which Fonterra has these modifications. This would be a Transpower/ PowerNet combined project. The net effect of any technology changes from coal to biomass is not expected until the second halve of the 10year demand forecast. A 10MVA to 15MVA demand increase, between 2028 to 2030, is possible but require further investigations in future years along with Fonterra and their business strategy.

More generally, the load at Edendale GXP is approaching the continuous rating (30MVA) of Transpower's T1/T2 transformer at Edendale bank. This puts supply at risk in the event of one transformer being out of service. PowerNet is working with Transpower and Fonterra to understand the upgrade options of the summer and winter ratings of the transformers so as to understand the supply risk and possible mitigation measures.

Control measures include increased load control, tie point and load shifts to other GXPs, and Special Protection Schemes which will automatically shed load in the event of a transformer tripping.

These two issues will need to be looked at as a combined entity.

Kingston 66kV

When the load increases beyond the capability of the 22kV circuit to Kingston, a zone substation, to be known as Kingston 66/22kV 5MVA substation, will be required. The subtransmission supply will be 66kV and supplied from the Athol 66kV supply point. The network extension will require a new 35km overhead line to be constructed. Initially a 66kV single circuit will be constructed, utilising the 22kV network as a backup supply. In the following years the substation will require a second 66kV supply to provide firm capacity to the 5MVA demand.

Implementation of the project is completely dependent on the demand requirements and realisation of the Kingston Village Limited subdivision.

North Makarewa-Frankton 66kV Strengthening

The Queenstown regional area, including Frankton, is currently one of the fastest developing regions in the South Island. The area is supplied with a single GXP station. The GXP is supplied via a single double circuit 110KV supply from Cromwell.

The existing Transpower Frankton transmission network, is approaching the safe firm capacity level of 70MVA, with the peak period occurring during the winter months when the demand requirements almost doubles from the peak summer period. Various options are considered by Transpower, OtagoNet and Aurora. This includes interim solutions including battery storage and generators to more permanent long term solutions including re-conductoring, transformer upgrades and the construction of a new transmission circuit.

In addition, PowerNet is exploring alternative supply connections from the 66kV subtransmission network to Frankton. In addition to the additional capacity requirements at Frankton, the extension of the networks will also address the Kingston 66kV future connection. A further consideration of the study is to determine the feasibility of interconnection between Gore/North Makarewa/Frankton networks improving the overall stability and redundancy of the subtransmission grid.

66kV Supply from Gore GXP

This project will create a 66kV supply point at Gore GXP by installing a 33/66kV step up transformer adjacent to the Gore GXP site. This 66kV supply point will be used to provide a second 66kV supply to the Riversdale substation. The existing Gore to Riversdale line (operating at 33kV) has been reinsulated to 66kV. This project will also need to upgrade the 33/11kV transformer at Riversdale to 66/22kV.

Colyer Road Third 33kV Line

If any further additional major load growth requests are received for the Colyer Road zone substation supply point, this would mean either that a third 33kV subtransmission line would need to be constructed from Invercargill GXP or the upgrade of the existing lines.

Additional Milk Processing

Additional Milk Processing plants at existing or new sites.

Electrification of Heat Processing plants

The creation of the investment fund, by National Government, to support the conversion of coal and gas boilers to electricity supply, have resulted in a number of market enquiries. The typical capacity requirements would require network upgrades, at either a subtransmission or zone substation level, to support demand.

Data Centres

The establishment of new data centres, requiring high level of supply availability, will require upgrades on the 33kV network between Invercargill and North Makarewa GXP's. Capacity will be limited to suitable levels at 33kV. The level of supply security will determine suitable locations within the network to accommodate the data centre.

Certain data centre demand requirements, may make it more economical to be connected directly onto Transpower's 220kV network.

Coal to Liquid Plants

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

Mines

Possible mineral extraction with power required to operate the mine and/or process the material. Possible resources include coal, lignite, silicon, gold, or platinum.

Oil Refineries

Possible major new industry that may require a new substation and subtransmission lines, most likely would be onto the Transpower 220kV network.

Wind farms

It is possible that there may be one or more large (>5MW) wind farm projects which come to fruition. These may require new subtransmission lines and/or zone substations.

This includes the potential Kaiwera Downs wind farm proposal which is classed as a contingent project at the moment.

4.5. Distributed Generation Policy

The value of distributed generation can be recognised in the following ways:

- Reduction of peak demand at the Transpower GXP.
- Reducing the effect of existing network constraints.
- Avoiding investment in additional network capacity.
- Making a very minor contribution to supply security where the customers are prepared to accept that local generation is not as secure as network investment.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.

It is also recognised that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Increased line losses if surplus energy is exported through a network constraint.
- Stranding of assets, or at least of part of an asset's capacity.
- Raising voltage above regulated levels to enable export of electricity

Despite the potential undesirable effects, the development of distributed generation that will benefit both the generator and TPCL is actively encouraged. The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings, with a guideline and application forms available on the web at http://www.powernet.co.nz/your-power-supply/distributed-generation/

Connection Terms and Conditions (Commercial)

- Connection of up to 10kW of distributed generation to an existing connection to the network will not incur any additional line charges. Connection of distributed generation greater than 10kW to an existing connection may incur additional costs to reflect network up-sizing.
- Distributed generation that requires a new connection to the network will be charged a standard connection fee as if it was a standard off-take customer.
- An application administration fee will be payable by the connecting party.
- Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.
- Any benefits of distributed generation that arise from reducing TPCL's costs, such as transmission costs or deferred investment in the network, and, provided the distributed generation is of sufficient size (greater than 10kW) to provide real benefits, will be recognised and shared.
- Those wishing to connect distributed generation must have a contractual arrangement with a suitable party in place to consume all injected energy – generators will not be allowed to "lose" the energy in the network.

Safety Standards

- A party connecting distributed generation must comply with any and all safety requirements promulgated by TPCL.
- TPCL reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

Technical Standards

- Metering capable of recording both imported and exported energy must be installed if the owner of the distributed generation wishes to share in any benefits accruing to TPCL. Such metering may need to be half-hourly.
- TPCL may require a distributed generator of greater than 10kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.
- All connection assets must be designed and constructed to technical standards not dissimilar to TPCL's own prevailing standards.

Congestion Policy

TPCL notes all medium distributed generation connections (>100kW) on the North Makarewa GXP are subject to congestion due the existing generators resulting in this GXP exporting. This means distributed generators >100kW will likely be subject to High Voltage Direct Current (HVDC) Link charges.

4.6. Use of Non-Network Solutions

As discussed in section 4.1 the company routinely considers a range of non-asset solutions and indeed TPCL's preference is for solutions that avoid or defer new investment. Table 45**Error! Reference source not found.** outlines how TPCL considers various investment options.

Table 45: Classes of Investment options

Class of Option	Description	Residual risk	PowerNet preference
Do-nothing	Intervention limited to minor operational fixes.	Loss of supply risk unmitigated, likely to increase over time.	This option is generally avoided unless the residual risk is demonstrated to be acceptably low.
Non-network	Network switching to shift load. Interruptible tariffs to manage demand. Install additional cooling to increase asset capacity.	Can increase network losses.	These options tend to only defer rather than avoid investment.
	Install batteries to meet peak demand.	Mitigation of loss of supply risk depends on battery capacity and discharge duration.	
	Install embedded generation to relieve constraints.	Relies on embedded generation operating during periods of network congestion to reduce loss of supply risk.	
Network	Traditional copper and concrete investment to increase asset capacity, reliability, security etc.	Loss of supply risk tends to be fully mitigated, but can be offset by risk of investment stranding.	Tends to be the only practical long-term option, especially where the network is already heavily loaded.

Effectiveness of tariff incentives is lessened with Retailers repackaging line charges that sometimes removes the desired incentive. 'Use of System' agreements include lower tariffs for controlled, night-rate and other special channels.

Load control is utilised to control:

- Transpower charges by controlling the network load during the LSI peaks.
- GXP load when maximum demand reaches the capacity of that GXP.
- Load on feeders during temporary arrangements to manage constraints.

Load shedding may be used by some customers where they accept a reduction of their load instead of investing in additional network assets.

Generators (owned by PowerNet) are sometimes used to minimise the impact of significant planned outages on TPCL network.

The acquisition of a mobile substation raises the threshold at which TPCL justifies converting a single-transformer substation to a dual-transformer site; resulting in significantly deferred growth-related investment on the larger single-transformer substations.

Where the nature of the load and network permit, stand-by generators and network storage solutions (batteries) are considered as an alternative to line upgrades.

Other low investment options typically considered include;

- Conductor upgrades
- Voltage regulators
- Pumps and fans on power transformers
- Tie point shifts

It is however noted that there are limits to the capabilities of low investment options to meet growth when the capacity headroom is used up or when demand growth is significant or step-changes in demand are occurring.

4.7. Non-network Development

IT Services

TPCL receives IT and management services support through its management services contract with PowerNet. Whilst it does not directly develop the GIS (Intergraph) or AMS (Maximo) systems, it does in conjunction with PowerNet develop interfaces and processes around these systems.

Smart Energy Home

PowerNet's Emerging Technologies programme has been exploring the impact that solar PV, battery storage, electric vehicles and other 'smart' technology might have on TPCL networks as these technologies develop and the cost becomes more affordable. Out of this project, it has become apparent that emerging technologies are set to have a large impact and while not immediate it is important for TPCL to understand as much as possible about them before they arrive in large numbers.

The Smart Energy Home is based in TPCL's owned house at 245 Racecourse Road. The house has the following smart energy features;

- 4kW solar PV system (14 panels and inverter)
- 10kWh battery for energy storage
- Electric vehicle – Nissan Leaf
- Electric vehicle charging station
- Hot water heat pump unit
- Heat pumps in living room and hall way for space heating
- Insulation under floor and in the ceiling
- Lighting converted to LED

A monitoring system has been installed that will meter consumption individually from the key technologies and significant appliances in the home. This data will be collected for analysis by PowerNet to assess how these technologies operate and are being used.

The retail electricity pricing package has pricing that varies through the day and been chosen to provide an incentive to use power in a way that is most efficient for TPCL's networks (using less power over peak demand times); the technologies installed are all geared toward helping people with this.

The home will be tenanted to understand how a consumer would use these technologies.

4.8. TPCL's Forecast Capital Expenditure

The forecast capital expenditure for TPCL is shown in Table 46. These figures are also provided in the information disclosure schedule 11a included in Appendix 3.

Table 46: TPCL's Forecast Capital Expenditure – ($000 – constant 2020/21 terms)

CAPEX: Consumer Connection	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Customer Connections (≤ 20kVA)	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,000
Customer Connections (21 to 99kVA)	522	522	522	522	522	522	522	522	522	489
Customer Connections (≥ 100kVA)	644	644	644	644	644	644	644	644	644	603
Distributed Generation Connection	6	6	6	6	6	6	6	6	6	6
New Subdivisions	383	383	383	383	383	383	383	383	383	358
	2,624	**2,624**	**2,624**	**2,624**	**2,624**	**2,624**	**2,624**	**2,624**	**2,624**	**2,456**

CAPEX: System Growth	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Riversdale Substation Upgrade			1,557	1,557						
Kelso Transformer Upgrade					141					
Glenham Transformer Upgrade					1,411					
Lumsden / Riversdale 22kV Line Upgrades	1,371	425	425	437						
22kV Upgrade Athol - Kingston	910	2,119	1,506	2,309						
Easements	31	31	31	31	31	31	31	31	31	29
Unspecified Projects					1,510	3,176	3,176	3,176	3,176	2,973
	2,311	**2,575**	**3,519**	**4,334**	**3,092**	**3,207**	**3,207**	**3,207**	**3,207**	**3,002**

CAPEX: Asset Replacement and Renewal	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Transformer Replacement	862	862	862	862	957	957	957	957	1,685	1,577
Ground Mount Platform Transformers	655	655	655	655	727	727	727	727		
11kV Line Replacement	5,334	5,334	5,334	5,334	6,003	6,840	6,840	6,840	6,840	6,403
Subtransmission Line Replacement	127	127	127	127	127	127	127	127	127	119
Zone Substation Minor Replacement	101	101	101	101	101	101	101	101	101	94
RTU Replacement	150	150	150	150	150	150	150	150	150	141
Mobile Regulator Control Replacement	71									
Relay Replacement	56	56	56	56	56	56	56	56	56	53
Communications Replacement	82	82	82	82	82	82	82	82	82	77
General Technical Replacement	38	38	38	38	38	38	38	38	38	36
Tower Inspection Remediation Works	119									
ABS renewals	1,548	1,606	1,604	780	1,267	1,267	1,267	1,267	1,196	
Power Transformer Refurbishment	912	435	279	279	279	408	279	279	279	261
Orawia Substation Upgrade		652	652							
Makarewa Switchboard Replacement				211	1,818					
Bluff Switchboard Replacement				209	1,340					
Gore Ripple Plant Upgrade	154									
Seaward Bush RTU, Arc Flash & Structure Replacement	598									
KF CB Replacement - Waimumu & Robsons										
RMU Renewals	220	142	142	142	142	142	142	142	142	133
Gore LV Link Box Renewals	110									
Pole Reinforcement	262	262	262	262	262	262	262	262	262	245
Condition Based Asset Replacements						5,205	5,205	5,205	5,205	4,872
LV Pillar Box Replacements and Refurbishments	688	688	688	688	688	688	688	688	688	644
33kV Oil Circuit Breaker Replacement	416	416	416	416	416	416	416	624		
Decommision Awarua substation and supply Sawmill at 11kV					1,666					
	12,503	**11,606**	**11,449**	**10,392**	**16,122**	**17,467**	**17,339**	**17,547**	**16,851**	**14,656**

CAPEX: Asset Relocations	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Line Relocations	118	118	118	118	118	118	118	118	118	110
	118	**118**	**118**	**118**	**118**	**118**	**118**	**118**	**118**	**110**

CAPEX: Quality of Supply	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Supply Quality Upgrades	350	350	350	350	350	350	350	350	350	327
Mobile Substation Site Made Ready		231		231						
Network Improvement Projects	121		121		121	121	121	121	121	113
	471	**581**	**471**	**581**	**471**	**471**	**471**	**471**	**471**	**441**

CAPEX: Legislative and Regulatory	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31

CAPEX: Other Reliability, Safety and Environment	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Earth Upgrades	2,947	2,926	2,926	2,839	1,210	1,210	1,210	1,210	1,210	1,133
Substation Safety	244	244								
Remote Area Power Supply	133	133	133			131	262	262	262	245
Hillside Protection Remediation	369									
Communications Projects	480	322	177	175	175	175	202	347	347	325
	4,174	**3,625**	**3,236**	**3,014**	**1,385**	**1,516**	**1,674**	**1,820**	**1,820**	**1,704**

Total Network CAPEX	22,200	21,129	21,416	21,063	23,811	25,402	25,432	25,786	25,090	22,369

5. Lifecycle Planning

Development criteria, the subject of the previous section, determine the need for particular assets. Once this need has been established each asset must be managed throughout its lifecycle to create and maintain the fulfilment of the assets purpose as long as it is required and to minimise any adverse effects the asset might create.

5.1. Lifecycle Asset Management Processes

Following procurement of equipment and materials, assets are constructed or installed as per a design or network standard and commissioned through a process to ensure the asset is capable of operating as intended. The asset then enters its useful service life where it will often be operated over a considerable time period. Maintenance activities are generally undertaken throughout an assets operational life to support its continued reliable service for as long as it is economic to do so.

Lifecycle asset maintenance drivers:

- Support continued reliable service to customers
- Economic viability when compared to replacement
- Continued safety
- Operational efficiency
- Rate and extent of deterioration
- Criticality
- Probability of failure

At some point the asset will reach its end of life and is retired from service. Assuming the need remains the asset will be replaced while the retired asset must be disposed of appropriately. This process is outlined in Figure 44 below.

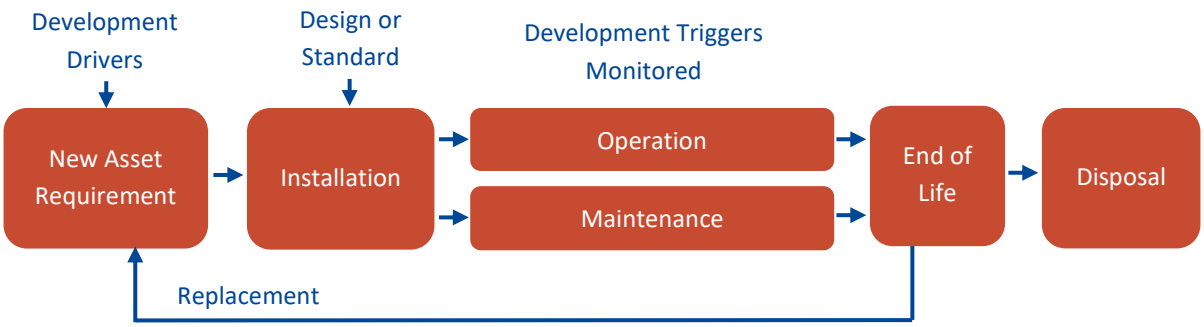


Figure 44: Asset Lifecycle

TPCL follows several asset management procedures to manage network assets throughout these lifecycle stages as referenced in Appendix 1.

Lifecycle asset maintenance drivers:

- Support continued reliable service to customers
- Economic viability when compared to replacement
- Continued safety

- Operational efficiency
- Rate and extent of deterioration
- Criticality
- Probability of failure

Installing Assets

The drivers for installation of new assets are as explained in the development section. Similarly the drivers requiring an asset on the network may change during the asset's operational life, and so may change the viability of maintaining or replacing an asset. Therefore these drivers need to be monitored beyond the installation to ensure the overall objective of providing an efficient cost effective service is achieved.

More complex assets such as a zone substation will require substantial design work to be completed, while standards are used to guide the construction and installation of more routine tasks such as the installation of a distribution transformer. Equipment and materials are procured as per the design or standard to be implemented and in line with TPCL's standardisation requirements (which are incorporated into designs and standards) as far as possible.

Assets are then installed to the design or standard followed by a commissioning process which is either specified in the design or (for standardised installations) using a commissioning checklist to ensure the asset has been installed and will function as intended prior to putting into service.

Operating TPCL's Assets

Operation of TPCL's assets predominantly involves simply letting the electricity flow from the GXPs to customer's premises year after year with occasional intervention when a trigger point is exceeded. However the workload arising from tens of thousands of trigger points is substantial enough to merit a dedicated control room. Altering the operating parameters of an asset such as closing a switch or altering a voltage setting involves no physical modification to the asset, but merely a change to the asset's state or configuration.

Operation of the network is effectively the service that TPCL's customers pay for, so it is the customer desire which forms the driver for the continuous operation of assets the optimal balance between reliability and cost.

Maintaining TPCL's Assets

Maintenance is primarily about replacing consumable components. Many of these components will be designed to "wear out" over an asset's design life and achieving the expected service life depends on such replacements. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts and loss or contamination of lubricants.

Continued operation of such components will eventually lead to failure as indicated in Figure 40. Exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, ambient temperature, previous maintenance history and presence of contaminants – note that the horizontal axis in Figure 45 is not simply labelled "time".

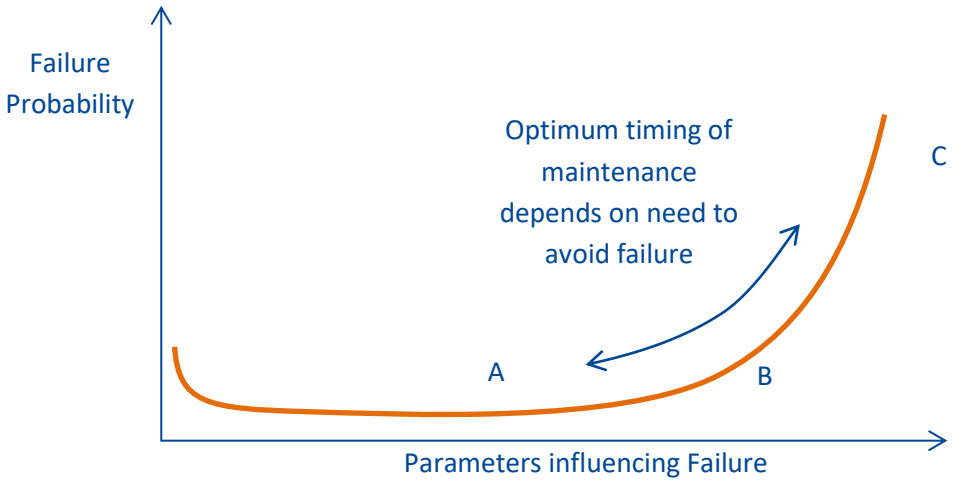


Figure 45 – Component Failure

This probability of failure curve can also be viewed as applicable to the overall asset life in which case neglecting maintenance could result in a considerable contraction along the "parameters influencing failure" axis. Conversely appropriate maintenance activities would stretch out the curve toward the expected design life; effectively resetting or pushing out the increasing probability of failure. There is often a significant asymmetry associated with consumables; for example replacing a lubricant may not significantly extend the life of an asset, but not replacing a lubricant could significantly shorten the asset's life.

Like all TPCL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoidance of supply interruption. Increasing maintenance costs (labour and consumables) over the asset's lifecycle taken together with the cost of discarding unused component life must be traded off against the desire to avoid failure. The optimal time for maintenance depends on an asset's criticality (impact of failure on customers) and ultimately on how much TPCL's customers are willing to pay to reduce probability of failure.

The practical effect of this is that assets supplying large customers or numbers of customers such as a 66/11 kV substation transformer may only be operated to point B in Figure 45 and condition will be extensively monitored to minimise the likelihood of supply interruption whilst assets supplying only a few customers such as a 15 kVA transformer will more than likely be run to failure represented as point C. In the extreme case of, say, turbine blades in an aircraft engine it would be desirable to avoid even the slightest probability of failure hence the blades may only be operated to point A.

Condition assessment is an important part of determining maintenance requirements, because many components do not deteriorate at a predictable age. Condition assessment allows deferral of maintenance cost for assets that are in good condition, and permits maintenance to be focused on the more deteriorated assets. Condition assessment involves inspections and testing to gather information about the condition of assets and their components, and can incorporate follow-up analysis (condition monitoring) to infer the condition of the asset through establishing trends in observable criteria.

By contrast some components are maintained at fixed intervals or operation counts. An example is replacing contacts in a circuit breaker which are pitted or eroded with each operation but are unable to be inspected without dismantling the circuit breaker (by which time the contacts can be replaced with a relatively small incremental cost).

As the value of an asset and the need to avoid loss of supply both increase, the company relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or

number of trips) and more and more on actual component condition (through such means as dissolved gas analysis (DGA) of transformer oil).

Replacement and Renewal of TPCL's Assets

Renewals or refurbishments are more significant maintenance activities that generally focus on the non-consumable components of assets to achieve an extension to the originally expected life. This is typically less routine work and often represents a significant milestone in the life of an asset. Renewal may ultimately be part of a full asset replacement programme where the component replacements are "staggered" over time (a bit like "Grandpa's axe"). This would be the typical approach for an overhead line where the components (poles, cross-arms, and conductors) wear out and are replaced at different rates but the result is complete replacement of the original line, perhaps several times over as long as the line asset is required.

Ultimately an asset will reach end of life when it either fails or deteriorates to the point it becomes uneconomic to repair or maintain. This will occur when failure causes significant damage to the overall asset (highly likely for failures at distribution or subtransmission voltages) or when a "non-consumable" part of the asset has significantly aged or deteriorated, for example paper insulation in a transformer. The key factor being that it then becomes more cost effective to simply replace the asset.

Retiring and Disposing of TPCL's Assets

Retiring assets generally involves de-energising the asset and disconnecting it from the network before removal from site or abandoning in-situ (typical for underground cables). Removed assets must be disposed of in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos. The asset will be removed from the regulatory asset base.

Key criteria for retiring an asset include:

- Its physical presence is no longer required (usually because a customer has reduced or ceased demand).
- It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.
- There are no suitable opportunities for re-deployment after an asset has been replaced to increase capacity or where more economic options exist to create similar outcomes e.g. new technology offers a low cost maintenance free replacement.
- It becomes uneconomic to continue to maintain the asset as it is more cost effective to replace with a new asset.

5.2. Routine Corrective Maintenance & Inspection

Network assets are inspected routinely with the frequency dependant on the criticality of the assets and the outcome focussing on failure avoidance. Recognising that some deterioration is acceptable, inspections are intended to identify components which could lead to failure or deteriorate beyond economic repair within the period until the next inspection.

Deterioration is noted and may trigger corrective maintenance if economic, especially where deterioration can be "nipped in the bud", for example touching up paint defects before rust can take hold. Other forms of deterioration are unable to be corrected (or improved) for example pole cracks

or rotting and noting these issues may become a trigger for replacement or renewal depending on the extent of deterioration i.e. loss of structural integrity.

Inspections are not able to cover all assets such as cables buried underground and may be limited by the availability of outages or the added effort (labour cost) required to remove covers. Therefore for the most part routine inspections are limited to what can be viewed from a walkover of the assets.

Testing supplements network inspections and although it typically requires additional time and skilled staff, testing has strong advantages over visual inspection if cost effective. It is generally possible to gain greater detail around asset condition and often allows collection of condition data without the need to remove covers for inspection. Testing may be destructive or non-destructive. For example insulation resistance (IR) testing gives an ohmic value for insulation under test whereas very low frequency (VLF) testing is “pass-fail” where a pass proves integrity of insulation but a fail will cause a fault which needs to be repaired.

TPCL’s Maintenance Approach

Most technical equipment such as transformers, switchgear and secondary assets are maintained in line with manufacturer’s recommendations as set out in their equipment manuals. Experience with the same types of equipment may provide reason to add additional activities to this routine maintenance. Visual inspections and testing also determine reactive maintenance requirements to maintain the serviceable life of equipment which are not routine but across a large asset base provide an ongoing need for additional maintenance resource.

Overhead line inspections are an economic means to prevent a large proportion of potential faults so the basic approach is to inspect these assets and perform preventative maintenance over the most cost effective period that achieves the desired service levels. A certain frequency of failure is accepted on overhead lines where this remaining proportion of failures becomes uneconomic to repair. This recognises customers’ acceptance of a low number of outages and the increasing cost for diminishing returns in attempting to reduce fault frequency.

As cables are underground they are unable to be inspected and testing is generally not cost effective and difficult to obtain accurate results to predict time to failure. Cables are therefore often run to failure. However as the relatively young cable network ages and fault frequency begins to increase a more preventative strategy will be employed based on testing to determine condition for critical cables.

In terms of cost efficiency, failures are relatively acceptable for lines and cables compared to the more technical assets. Significant serviceable life can be restored by repairing a fault due to the distributed nature of these assets and the relatively minor (i.e. localised) effect of faults. Asset criticality must allow for the occurrence of outages however increased security (redundancy) is often applied as more effective than attempting to determine time to failure and performing preventative maintenance.

Table 47 sets out the maintenance approaches applicable to each network asset category and the frequency with which these maintenance activities are undertaken.

Table 47: Maintenance Approach by Asset Category

Asset Category	Sub Category	Maintenance Approach	Frequency
Subtransmission	O/H	Condition Monitoring through periodic visual inspection.	5 yearly
		Testing of various pole structures, Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
	U/G	Generally run to failure and repair.	Annual
		Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Sheath insulation IR tested.	
		Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	As occurs
	Distributed Sub Transmission Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection.	5 yearly
		Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	
		Lubrication of moving parts.	
Zone Substations	Sub Transmission Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition.	Monthly
		Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics.	5 Yearly
		Corrective maintenance as required after any concerning inspection or test results.	As discovered
	Power Transformers	Condition monitoring through periodic inspections.	Monthly
		Winding resistances, Insulation resistance, Function checks on auxiliary devices (Buchholz, pressure relief, thermometers).	Annual
		Tap changer servicing; mechanism and contacts inspected – replacements as necessary, DC resistance across winding each tap, diverter resistors resistances	Operation Count
		Predictive maintenance - oil analysis (dissolved gasses, furan) to estimate age and identify internal issues arising or trends; frequency increased if issues and trends warrant. Oil processed as necessary.	Bi-Annual
		Clean up and repair of corrosion, leaks etc. and replacement of deteriorated or damaged components. Replacement of breathers when saturated.	As discovered
		Paper sample may be taken to estimate age for aged transformers in critical locations at Engineer's instruction or otherwise during major refurbishment work at unit's half-life.	Half life
		Swept frequency test at start of life and after significant events such as relocation, repaired fault, refurbishment done to check for internal movement of components.	After Significant Event
	Distribution Voltage Switchgear	Condition Monitoring through periodic visual inspection checking for; operation count, gas pressure, abnormal or failed indications and general condition.	Monthly
		Testing; Contact Resistance, Partial Discharge, Insulation Resistance, CB operation time, Cleaning of contacts, Thermal Resistivity viewed soon after unloading, VT/CT IR and characteristics.	5 Yearly
		Corrective maintenance as required after any concerning inspection or test results.	Non-periodic
	Other (Buildings, RTU, Relays, Batteries, Meters)	Monthly sub checks include inspection of auxiliary and other general assets for anything untoward; structures,	Monthly

Asset Category	Sub Category	Maintenance Approach	Frequency
		buildings, grounds and fences for structural integrity and safety and general upkeep; rusting, cracked bricks, masonry or poles and weeds etc. Maintenance repairs and general tidying as necessary. Protection relays are tested typically with current injection to verify operation as per settings. Any alarms or indications from electronic equipment or relays reset and control centre notified for remediation. Meters recertified by external technicians as regulations require.	5 yearly
		Otherwise any other equipment visually inspected for anything untoward.	Non-periodic
Distribution Network	O/H	Condition Monitoring through periodic visual inspection. Testing of various pole structures, Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Generally run to failure and repair. Inspection of visible terminations as part of zone substation checks and otherwise opportunistic inspection if covers removed for other work. Testing generally in conjunction with fault repair but may be initiated if anything untoward is noted during other inspections or work; may use IR, PI, TR, PD, VLF.	Reactive or opportunistic 5 yearly if viable
	Distributed Distribution Voltage Switchgear (ABSs)	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components. Function tests to verify operation as per settings; for any switchgear controlled by relays.	5 yearly
Distribution Substations	Distribution Transformers	Condition monitoring through periodic inspections. Infrared thermal camera inspection units 500kVA and larger.	6 monthly or if <150kVA
		Clean up and repair of corrosion, leaks etc. Some units have breathers; replaced when saturated.	As discovered
		Winding resistances, Insulation resistance for older units if shut down allows.	Opportunistic
		DGA for critical end of life units.	Non-Periodic
	Distribution Voltage Switchgear (RMUs)	Condition monitoring visual inspection to assess deterioration or corrosion. Some minor repairs may be made but generally inspection determines when replacement will be required. Threshold PD tests to identify significant partial discharge.	6 monthly
		Periodic servicing undertaken including wipe down of epoxy insulation and oil replacement in critical switchgear. Some removed oil tested for dielectric breakdown as occasional spot check of general condition.	5-10 yearly
	Other	Inspection of enclosures for structural integrity and safety compromised by rusting or cracked brick or masonry. O/H structures included in distribution network inspections.	6 monthly
LV Network	O/H	Condition Monitoring through periodic visual inspection. Tightening, repair or replacement of loose, damaged, deteriorated or missing components.	5 yearly
	U/G	Run to failure and repair.	Reactive
	Link and Pillar Boxes	External inspection for damage, tilting, sinking etc. Internal components run to failure and repair. Corrosive lid replacement with alternative plastic units. Some opportunistic inspections when opened for other work.	5 yearly

Asset Category	Sub Category	Maintenance Approach	Frequency
Other	SCADA & Communications	Generally self-monitored with alarms raised for failures or downtime. 24/7 control room initiate response.	Reactive
	Earths	Five yearly inspections to check locational risk, check for standard installation and any corrosion, deterioration or loosening of components. Testing is done to confirm connection resistances and electrode to ground resistance is sufficiently low.	5 yearly
	Ripple Plant	Inspection along with other assets at GXP for signs of deterioration or damage of components; oil leaks, corrosion etc. Reactive remedial actions will follow for any issues found.	Monthly

Maintenance and Inspection Programmes

Budget descriptions for routine corrective maintenance and inspection activities are set out in Table 48 and forecasts are provided in Table 54 at the end of this section. These budgets tend to be ongoing at similar levels year after year but may be adjusted from time to time to allow for improvements in maintenance practice.

Table 48: Routine and Corrective Maintenance and Inspection Budget Descriptions

Budget	Description	Expenditure Range/Type
Routine Distribution Inspections	Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.	Cost Under $1.5M on-going; OPEX
Distribution Routine Maintenance	Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.	Cost Under $0.5M on-going; OPEX
Distribution Earthing Maintenance	Generally reactive work undertaken to correct issues found during the routine inspection and testing of earthing systems.	Cost Under $0.7M in 2021/22 & 2022/23 then Under 0.5M on-going; OPEX
Distribution Corrective Maintenance	Slightly more extensive maintenance than the routine maintenance above.	Cost Under $0.4M on-going; OPEX
BS Communications Routine Inspection and Checks	Ventia undertakes routine maintenance inspections on the communications equipment.	Cost Under $0.2M on-going OPEX
Technical Routine Inspections & Checks	Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.	Cost Under $1.0M on-going; OPEX
Technical Routine Maintenance	Routine maintenance at zone substations such as grounds, fence and building maintenance, rust repair and paint touch-ups. Routine maintenance at distribution substation assets such as cleaning, paint touch-ups and enclosure repairs. Routine maintenance for Ring Main Units such as cleaning, paint touch-ups and enclosure repairs. Includes reactive work undertaken to correct issues found during the routine technical inspection. Also a general budget for all minor technical work.	Cost Under $1.5M on-going; OPEX
Technical Corrective Maintenance	Correcting defects found in equipment	Cost under $0.25M on-going OPEX
Partial Discharge Survey	Routine partial discharge condition monitoring surveying of subtransmission cables, terminations and equipment to identify abnormal discharge levels before failure occurs.	Cost Under $0.1M on-going; OPEX
Infra-Red Survey	Routine Infra-Red condition monitoring survey of bus-work, connections, contacts etc. for abnormal heating as indication of poor electrical contact between current carrying components which may	Cost Under $0.1M on-going; OPEX

Budget	Description	Expenditure Range/Type
	lead to voltage quality issues and/or failure of equipment.	
Supply Quality Checks	Investigations into supply quality which are generally customer initiated.	Cost Under $0.1M on-going; OPEX
Spare Checks and Minor Maintenance	A budget for checks to confirm what equipment is kept in spares and perform minor maintenance required to ensure spares are ready for service.	Cost Under $0.1M on-going; OPEX
Connections Minor Maintenance	Undertake minor maintenance on customer connections equipment.	Cost Under $0.2M on-going from 2021/22; OPEX
RAPS Maintenance	A new budget for the maintenance of remote area power supplies	Cost Under $0.1M ongoing from 2021/22; OPEX
Earthing Inspections	Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed for all earths on a five yearly basis	Cost Under $0.5M on-going from 2021/22; OPEX

Systemic Issues

One potential systemic issue has been identified. Grey porcelain insulators on EDE Air Break Switches manufactured between 1998 and 2014 have a potential defect which can result in water ingress. Over time this can cause the insulator to crack and break into pieces which can fall when the switch is operated. An appropriate remedial action program have been initiated from 2019/20 to mitigate, repair, or replace the affected ABS's.

A second potential issue is the possibility of moisture ingress in the 33kV Eaton Cooper circuit breakers. The typical construction of the circuit breaker is a single mould rigid steel tank with a mounted head. An O-ring gasket is used to prevent moisture ingress between the tank and head and bolted securely. Six Porcelain bushings are secured on the head with bushing gaskets to prevent moisture ingress. The tank is filled with oil to provide adequate electrical insulation between active/live parts and the tank and lid itself. Moisture ingress have been found within the oil, where it is absorbed by a barrier board used to mount the 33kV trip coil connections. This result in a compromised insulation withstand level within the breaker. A remedial action plan, including more regular testing and maintenance, in conjunction with the replacement of the breakers from 2021/22 financial year are being implemented.

Examples of past investigations and outcomes are shown below. Some of these examples represent learnings from issues found on other networks managed by PowerNet but which are common to TPCL network.

- Kidney strain insulators: Replaced with new polymer strains.
- DIN LV fuses: Sourced units that can be used outdoor.
- Parallel-groove clamps: Replaced with compression joints.
- Non-UV stabilised insulation: Exposed LV now has sleeve cover, with new cables UV stabilised.
- Opossum faults: Extended opossum guard length.

5.3. Asset Replacement and Renewal

The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their expected 45 year life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

Apart from whole of lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions. Replacement of assets may also be heavily influence by the development drivers discussed in section Development Criteria.

Innovations That Defer Asset Replacement

There are a number of innovations that TPCL uses to defer asset replacement. These include;

- Thermal (Infrared) and Partial Discharge (Corona) camera inspections of Zone Substation equipment
- Mid-life refurbishment of power transformers
- Dissolved Gas Analysis (DGA) of large distribution transformers
- Thor hammer analysis of poles
- Automation of switchgear to enable faster restoration in the event of fault sets out the approach to making decisions around when to undertake replacements or renews applicable to each network asset category.

Table 49: Replacement and Renewal Decisions by Asset Category

Asset Category	Sub Category	Replacement and Renewal Decision Approach
Subtransmission	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE cables replaced when reliability declines to an unacceptable level or repairs become uneconomic. Oil cables may be damaged beyond economic repair depending on nature of failure.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
	Distributed Subtransmission Voltage Switchgear (ABSs)	When inspection indicates deterioration sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic.
Zone Substations	Zone Substation HV Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Power Transformers & Regulator Transformers	After failure causing significant damage that is not economic to repair. Paper, Furan or DGA analysis indicating insulation at end of life. Tank and fittings deteriorating, lack of spare parts and not economic to maintain for aged units. Not economic to relocate (transport and installation costs) after aged transformers displaced e.g. for a larger unit.
	Medium Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other (Buildings, RTU, Relays, Batteries, Meters)	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Buildings and fences when not economic to maintain after significant accumulating deterioration or seismic resilience concerns. Bus work and conductors when not economic to maintain. Greater than Standard Life and maintenance required.
Distribution Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	XLPE or paper lead cables replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	Distributed Medium Voltage Switchgear	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
Distribution Substations	Distribution Transformers	Often replaced if rusting is advanced or other deterioration/damage is significant and maintenance becomes uneconomic.

Asset Category	Sub Category	Replacement and Renewal Decision Approach
		Otherwise units generally run to failure but transformers supplying critical loads may be replaced early based age or as part of other replacements at site. Units removed from service <100kVA and older than 20yrs are scrapped otherwise tested and if satisfactory recycled as stock.
	Distribution Voltage Switchgear (RMUs)	Replaced at end of standard life (fixed time), may be delayed in conjunction with condition monitoring to achieve strategic objectives. Significant damage from premature failure could require replacement.
	Other	Instrumentation/Protection at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic e.g. protection replaced with switchboard or transformer. Batteries replaced prior to the manufacturers stated life expectancy (typically 10 years) or on failure of testing. Enclosures not economic to maintain after significant accumulating deterioration or seismic resilience concerns.
LV Network	O/H	Reactive replacements after failure due to external force. Poles replaced when structural integrity indicated as low by pole scan or visual inspection. Generally poles cross arms, pins, insulators, binders and bracing etc. replaced when inspection indicates deterioration that could cause failure prior to next inspection and maintenance is uneconomic. Conductor replaced when reliability declines to an unacceptable level or repairs become uneconomic.
	U/G	Generally run to failure. Replaced when condition declines to an unreliable level e.g. embrittlement of insulation.
	Link and Pillar Boxes	Replaced if damaged or deterioration is advanced and could lead to failure before next inspection (or if public safety concerns exist).
Other	SCADA & Communications	RTUs or radios at end of manufacturers stated life (fixed time) or when obsolete/unsupported or otherwise along with other replacements as economic.
	Earths	Replaced when inspections find non-standard arrangements, deteriorated components or test results are not acceptable.
	Ripple Plant	Becoming obsolete as smart meters are installed across the network. Run to failure if security provided by backup plant.

Asset Replacement and Renewal Projects

Asset replacement and renewal projects that are not ongoing are described in Table 50. Table 53Table 51 and Table 52 often represent one-off replacement or renewal of significant assets that have reached end of life or a significant milestone in its life. Other projects may target a number of assets of similar age that will be replaced or renewed as part of short or medium term programme.

Table 50: Current (Year 1) Asset Replacement and Renewal Projects

Project and Description	Cost and Timing
Seaward Bush RTU, Arc Flash & Structure Replacement: The Seaward Bush substation has a number of secondary systems which were planned to be replaced as part of a Power Transformer renewal. The transformers have now been condition assessed in consultation with a transformer expert as having many years' service life remaining. This has led to the transformer renewal being removed as a project. The other renewal activities (RTU, arc flash and 33kV structure) are still planned and are combined in this project. The existing overhead 33kV bus structure will be replaced with two 33kV ring main units (RMUs) and short 33kV cable runs to poles adjacent to the substation. The 11kV switchboard will be retrofitted with arc flash detection sensors and new incomer CB protection relays to enable arc flash protection. The obsolescent Harris RTU will also be replaced with an SEL Axion RTU. Design and major equipment purchase are being completed in 2020/21 with construction being completed over a two year period ending in 2021/22.	CAPEX Cost under $0.6M for 2021/22 a
Mobile Regulator Control Replacement: Replacement of control system of mobile regulator. Scope to include new control, voltage regulating relay and DC supply.	CAPEX Cost Under $0.1M 2021/22
Communications Replacement: Equipment is becoming obsolete with manufacturers' ending support. This project will replace the total communications network with a modern scheme to provide the required communication for TPCL. The chosen scheme will be a combination of higher speed digital microwave radio (DMR) to replace the existing microwave links, and high speed point-to-multipoint broadband radio to zone substations. The overall aim is to achieve a minimum of 1Mbps (Megabit-per-second) speed over Internet Protocol to all of TPCL's zone substations.	CAPEX Cost $0.5M for 2020/21 & under $0.1M per annum 2021/22 to 2030/31
Gore Ripple Plant Upgrade. The existing Gore Injection controller, which connects back via UHF radio to the Main Frame Injection Controller at TPI, is the oldest in the fleet of injection station controllers. The existing controller needs to be replaced to improve the Ripple Plant with the Invercargill Control system.	CAPEX Cost Under $0.2M 2021/22
Gore LV Link Box Renewals: Replacement of underground link boxes in Gore which have deteriorated with age or have been damaged and are unfit for service.	CAPEX Cost Under $0.2M 2021/22

Table 51: Planned (Year 2 - 5) Asset Replacement and Renewal Projects

Project and Description	Cost and Timing
Orawia Substation Upgrade: The Orawia Substation control room building and transformer and overhead bus structures were identified as being at risk during seismic investigation. This project will replace the control room and make changes to the weight loading on the bus structures. Loading will be reduced by replacing pole mounted equipment with ground mounted equipment and replacing overhead conductor bus with either cable or conductor supported on dedicated equipment stands.	CAPEX Cost Under $1.5M per annum 2022/23-2023/24

Project and Description	Cost and Timing
Makarewa Switchboard Replacement: The Makarewa 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26.	CAPEX $0.1-$2.0M per annum 2024/25-2025/26
Bluff Switchboard Replacement: The Bluff 11kV Switchboard reaches its expected life of 45 years in 2025/26. Design to be completed in 2024/25 ahead of replacement in 2025/26. The new CB6 (installed in 2015) for connection of Flat Hill wind farm will be retained.	CAPEX $0.1-$1.5M per annum 2024/25-2025/26

Table 52: Considered (Year 6 – 10) Non-routine Replacement and Renewal Projects

Project and Description	Cost and Timing
Awarua Substation replacement: Awarua substation is a 5MVA, 33/11kV substation providing supply to a single ICP. The substation yard and HV equipment, including transformers have been identified for refurbishment and/or replacement. The new supply from Colyer Road substation is to supply the ICP and decommission the Awarua substation.	CAPEX Cost Under $2M 2025/26

Ongoing Replacement and Renewal Programmes

The remaining replacement and renewal budgets are for ongoing work that tends to require about the same expenditure year after year. These budgets are listed and described in Table 53 and expenditure forecasts are provided in Table 46 (CAPEX) and Table 54 (OPEX). A redefinition of work programmes to more closely align to Information Disclosure Determination definitions has resulted in a transfer of some distribution work from Routine Maintenance to Replacement & Renewal. A one-off adjustment in 2018/19 adapts the OPEX budgets below for a change in the financial treatment of these costs under a revised network management agreement.

Table 53: Replacement and Renewal Programmes

Budget	Description	Expenditure
Transformer Replacement	On-going replacements of distribution transformers, both pole and ground mounted, which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished.	Annual CAPEX Cost Under $2M per annum
11kV Line Replacement	On-going replacements of both medium and low voltage line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers both distribution lines, cables, dropouts and ABS's. This budget also covers • Red tagged pole replacement • Increasing road crossing height • Minor distribution renewals and upgrades	Annual CAPEX Cost Under $7.0M per annum
Subtransmission Line Replacement	On-going replacements of subtransmission line assets. These are identified through routine inspection.	Annual CAPEX Cost Under $0.2M per annum

Budget	Description	Expenditure
Zone Substation Minor Replacement	Minor work discovered during previous years inspections are combined by sites into projects. Covers on-going replacement of minor components at zone substations such as LTAC panels and battery banks.	Annual CAPEX Cost Under $0.2M per annum
RTU Replacements	This project will replace an average of three sites over each 2 year period. The focus is on the Harris RTU's. Some substation projects will include the RTU replacement and have costs included. i.e. Seaward Bush, Lumsden. This was chosen as the present units are becoming unreliable and full remote operation is required to meet the service levels. Rate of renewal could be increased if unreliability reaches unacceptable levels.	Annual CAPEX Cost Under $0.2M per annum
Relay Replacement	On-going testing and fault investigation sometimes highlight protection and control relays that are not performing as desired; this programme allows renewal of these with modern protection and control relays (includes Voltage Regulating Relays) Some replacements will occur with other replacement projects, i.e. Switchboard replacement projects	Annual CAPEX Cost Under $0.1M per annum
Communication Replacement	Budget to allow for the replacement of remote radio devices providing communication to selected distribution equipment.	Annual CAPEX Cost Under $0.1M per annum
General Technical Replacement	General replacement of technical items at Zone Substations such as DC systems and batteries.	Annual CAPEX Cost Under $0.1M
ABS Renewal Works:	The replacement of all grey porcelain ABS's installed between 1998 and 2014. Due to water ingress, insulators tend to crack and become unsafe during operation. The project will replace all identified units with either remote controlled load break or manual controlled air break switches. General replacement of other units identified as per the Asset Management program.	CAPEX Cost Under $2M per annum 2021/22 to 2029/30
Power Transformer Refurbishment	A budget to allow refurbishment work on large power transformers. Generally this work only insures that the power transformer will achieve its expected life.	Annual CAPEX Cost varies but generally between $0.3-1M per annum
RMU Renewals	Ongoing replacements of RMU's identified during site investigations and remedial maintenance. Consideration of equipment age (end of life) and performance considered.	Annual CAPEX less than $0.5M
Pole Reinforcement	On-going reinforcement of red tagged wooden poles identified with the MV and LV networks. Additional reinforcement of individual pole structures extend pole useful life and mechanical integrity for up to 15 years.	Annual CAPEX less than $0.5M per annum
LV Pillarbox replacement	Budget allowed for replacement of identified pillar boxes and the conversion of steel lids to non-conductive plastic units.	Annual CAPEX less than $1M per annum
33kV Oil Circuit Breaker Replacement	Replacement of high voltage circuit breakers identified within zone substations.	Annual CAPEX less than $0.7M between 2021/22 and 2028/29
General Distribution Refurbishment	Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like crossarms, insulators,	Annual OPEX Cost Under $1M per annum

Budget	Description	Expenditure
	strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	
Subtransmission Refurbishment	A budget to allow refurbishment work that doesn't impact on the valuation of the subtransmission assets. This covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.	Annual OPEX Cost Under $0.2M
Zone Substation Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the substation assets. Covers items like earth sticks, safety equipment, buildings, battery systems etc.	Annual OPEX Cost Under $0.1M
Power Transformer Refurbishment	A budget to allow refurbishment works that won't impact on the valuation of the power transformers. Covers items like painting.	Annual OPEX Cost Under $0.1M
Transformer Refurbishment	Refurbishment of distribution transformers such as rust repairs, paint touch-up, oil renewal, replacement of minor parts such as bushings, seals etc.	Annual OPEX Cost Under $0.1M

5.4. TPCL's Forecast Operation Expenditure

The forecast operational expenditure for TPCL is shown in Table 54.

These figures are also provided in the information disclosure schedule 11b included in Appendix 3. Two further categories not described earlier complete TPCL's forecasted operational expenditure budget as follows.

Vegetation Management

Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim and felling of trees has to be undertaken at TPCL's expense as required under the Electricity (Hazards from Trees) Regulations 2003.

TPC's future approach is to only pay for first trim or felling while customers are responsible for all further trimming and or the felling of vegetation. The existing practice of offering a second trim to owners where vegetation encroaches within the growth limit zone will not be offered in future. PowerNet will remove vegetation where owners submit a valid No interest Notice. A lifecycle asset management plan will be developed for all vegetation and be managed through Maximo.

External service providers are used to capture field data annually. All data is to be included in Maximo and GIS, where an existing data base exist. Based on the site condition assessment, a risk profile is to be developed from where PowerNet will schedule site activities to trim and/or remove vegetation, currently performed by approved service providers.

Current vegetation management practices utilised by PowerNet, follows industry best practice guidelines and legislative regulations. Draft proposals, including an increased MAD requirement are being considered and will be implemented once ratified and approved by industry. The possibility exist that restrictive conditions due to increased MAD requirements could impact on costs to manage vegetation effectively.

This OPEX cost is budgeted at under $1.5M per annum ongoing.

Service Interruptions and Emergencies

This budget provides for the provision of staff, plant and resources to be ready for faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers. Any follow-up actions necessary to make further repairs are charged to the appropriate Reactive Maintenance budget. This OPEX cost is budgeted at less than $4million per annum.

Table 54: TPCL's Forecast Operational Expenditure ($000 – constant 2020/21 terms)

OPEX: Asset Replacement and Renewal	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
General Distribution Refurbishment	575	575	575	575	575	575	575	575	575	575
Subtransmission Refurbishment	91	91	91	91	91	91	91	91	91	91
Zone Substation Refurbishment	60	60	60	60	60	60	60	60	60	60
Power Transformer Refurbishment	55	55	55	55	55	55	55	55	55	55
Transformer Refurbishment	20	20	20	20	20	20	20	20	20	20
Locks and Security	79	58	58	58	18					
	880	**860**	**860**	**860**	**820**	**802**	**802**	**802**	**802**	**802**

OPEX: Vegetation Management	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Vegetation Management	950	950	950	950	950	950	950	950	950	950
Vegetation Inspection and Admin	265	265	265	265	265	265	265	265	265	265
	1,215	**1,215**	**1,215**	**1,215**	**1,215**	**1,215**	**1,215**	**1,215**	**1,215**	**1,215**

OPEX: Routine and Corrective Maintenance and Inspection	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Routine Distribution Inspections	1,228	1,228	1,228	1,228	1,290	1,290	1,289	1,289	1,289	1,289
Distribution Routine Maintenance	301	301	301	301	316	316	316	316	316	316
Distribution Earthing Mtce	660	660	276	276	299	299	299	299	299	299
Distribution Corrective Maintenance	249	249	249	249	262	262	262	262	262	262
BS Communications Routine Inspection and Checks	97	97	97	97	102	102	102	102	102	102
Technical Routine Inspections & Checks	541	541	541	541	568	568	568	568	568	568
Technical Routine Maintenance	1,238	1,238	1,238	1,238	1,301	1,301	1,301	1,301	1,301	1,301
Technical Corrective Maintenance	172	172	172	172	172	172	172	172	172	172
Infrared Survey	21	21	21	21	22	22	22	22	22	22
Partial Discharge Survey	72	72	72	72	75	75	75	75	75	75
Supply Quality Checks	16	16	16	16	17	17	17	17	17	17
Spares Checks and Minor Maintenance	18	18	18	18	18	18	18	18	18	18
Connections Minor Maintenance	110	110	110	110	116	116	116	116	116	116
RAPS maintenance	3	8	11	14	16	19	21	24	27	29
Earthing Inspections	185	185	185	185	185	185	185	185	185	185
	4,910	**4,916**	**4,534**	**4,537**	**4,757**	**4,760**	**4,761**	**4,764**	**4,766**	**4,769**

OPEX: Service Interruptions and Emergencies	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Incident Response - Fixed Fee	214	214	214	214	214	214	214	214	214	214
Incident Response - Distribution - Unplanned	2,759	2,759	2,759	2,759	2,897	2,897	2,897	2,897	2,897	2,897
Incident Response - Communications - Fixed Fee										
Incident Response - Communications - Unplanned	55	55	55	55	57	57	57	57	57	57
Incident Response - Technical - Fixed Fee										
Incident Response - Technical - Unplanned	347	347	347	347	364	364	364	364	364	364
	3,374	**3,374**	**3,374**	**3,374**	**3,532**	**3,532**	**3,532**	**3,532**	**3,532**	**3,532**
Operational Expenditure Total	**10,380**	**10,365**	**9,983**	**9,986**	**10,324**	**10,308**	**10,310**	**10,313**	**10,315**	**10,318**

6. Risk Management

Risk is seen as any potential but uncertain occurrence that may impact the achievement of objectives and ultimately on the value of TPCL's business. TPCL is exposed to a wide range of risks and utilises risk management techniques to bring risk within acceptable levels. This section examines TPCL's risk exposures, describes what it has done and will do about these exposures and what it will do to reinstate service levels should disaster strike.

6.1. Risk Strategy and Policy

"Understand and Effectively Manage Appreciable Business Risk" is a key corporate strategy and critical business task within TPCL. As such, TPCL's asset management strategies (directly or indirectly) also incorporate risk management. PowerNet developed a risk management framework to formalise the practices for the effective management of risks that TPCL's business faces. This will ensure greater consistency in the quantification of various risks and correct prioritisation of their mitigation, as well as ensuring the regularity of review. The framework is consistent with the ISO Standard ISO 31000:2009 Standard: Risk Management - Principles and Guidelines.

PowerNet's risk management methods are used to manage TPCL's risk to acceptable levels with decision making around TPCL's asset management related risks guided by the following principles:

- Safety of the public and staff is paramount.
- Essential services are a second priority.
- Large impact work takes priority over smaller impact work.
- Switching to restore power supply takes priority over repair work.

Risk plans will in general only focus on one major event at a time.

Risks need to be identified before they can be mitigated. Many risks might seem obvious, yet the identification of other ones require experience and insight into the many factors that could have a significant impact on business objectives. The following risk categories have been established to ensure that various risk types are considered and review responsibility be allocated to the applicable manager:

- Health and Safety.
- Environmental.
- Financial.
- Network Performance.
- Operational Performance.
- Reputation.
- Governance.
- Regulatory Change and Compliance.

This top-down approach is supplemented by a less formal bottom-up process where staff are encouraged to consider and report any risks as they become evident. The Health and Safety category is an exception as a formal policy exists to ensure as many incidents as possible are proactively reported (including near hits) to help identify hazards and control measures as a priority.

Risk categories are reviewed when there is a change in perception of the risks that TPCL faces, especially following events which may affect local networks, other catastrophic events which might have global impact, or a change in regulations which may require risk to be considered in greater detail.

Risk Quantification

Once a risk has been identified it must be quantified. This is done by determining the following two factors:

- The severity of consequences associated with the risk.
- The probability that the consequences will be encountered.

These factors are categorised using relative terms as indicated the following tables to encourage an intuitive assessment of consequence and probability. This categorisation also allows for the use of more robust calculations where practical (especially regarding probability).

Table 55: Consequence Description

Consequence	Description
Insignificant	Operational impact easily handled through normal internal control processes
Minor	Some disruption possible; able to be managed with management input
Moderate	Significant disruption possible; managed with additional management input and resources
Major	Business operations severely damaged or disrupted; requires extraordinary management input and resources
Extreme	Disaster; extreme impact on staff, plant, and/or operations

Table 56: Event Consequence Categorisation

Consequence					
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Health and Safety	First aid treatment	Medical treatment injury or illness	Lost time injury or illness	Serious permanent disabling injury/illness	Fatality/fatalities
Environmental	Reversible impact, addressed immediately, remediated < 24 hours	Reversible impact, addressed short term, remediated < 1 week	Reversible impact, addressed medium term, remediated < 1 month	Long term recovery typically taking years	Irreversible widespread damage to environment
Financial	Asset impact of < 0.1% or revenue impact of < 0.1%	Asset impact > 0.1% and < 0.2% or revenue impact > 0.1% and < 1%	Asset impact > 0.2% and < 1% or revenue impact > 1% and < 10%	Asset impact > 1% and < 20% or revenue impact > 10% and < 50%	Asset impact of > 20% or revenue impact of > 50%

Consequence					
Risk Category	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Network Performance	Exceeding SAIDI/SAIFI limits during year, actively managing performance	Exceeding SAIDI/SAIFI limits during year, increased management effort and intervention required	Recoverable and explainable breach of SAIDI or SAIFI regulation (no underlying asset condition issues)	Significant breach of SAIDI/SAIFI regulations triggering investigation and penalties (underlying systemic asset condition issues)	Ongoing repeated significant breaches resulting in loss of control of AMP programme due to regulatory intervention
Operational Performance	Operational impact easily handled through normal internal control processes	Some disruption possible; able to be managed with management input	Significant disruption possible; managed with additional management input and resources	Business operations severely damaged or disrupted; requires extraordinary management input and resources	Disaster; extreme impact on staff, plant, and/or operations
Reputation	Social media attention - one-off public attention	Attention from recognised regional media - short term impact on public memory	Ongoing attention from recognised regional media and/or regulator inquiry	Attention from recognised national media and/or regulator investigation - medium-term impact on public memory	International media headlines and/or government investigation - long-term impact on public memory
Governance	Board awareness	Board and shareholder awareness	Perception of systematic underperformance, shareholder concern	Ongoing shareholder dissatisfaction	Dysfunctional governance - major conflicting interests or fundamental change in governing board of directors
Regulatory Change and Compliance	Audit provisional improvement notice	Minor non conformance	Breach with risk of prosecution or emerging regulatory change with potential to affect business	Prosecution of Director and/or officers or regulatory change enacted	Breach resulting in imprisonment of Director and/or officers or appointment of statutory board to a network or impact of regulatory change resulting in complete business transformation

Table 57: Event Probability Categorisation

Likelihood	Description	Frequency
Almost Certain	The consequence is expected to occur in most circumstances	Occurs three times or more per year
Likely	The consequence has a reasonably high chance of occurring in many circumstances	Occurs once or twice per year
Possible	The consequence could conceivably occur in some circumstances	Typically occurs in 1-10 years
Unlikely	The consequence is unlikely to occur in most circumstances	Typically occurs in 10-100 years
Rare	The consequence would occur only in exceptional circumstances	Greater than 100-year event

Risk Ranking

Consequence and probability provide an overall measure of a risk. The risk matrix in Table 57 indicates how these factors can be combined to present a relative risk level.

Table 58: Risk Ranking Matrix

		Consequence				
	Risk Rating	**Insignificant**	**Minor**	**Moderate**	**Major**	**Extreme**
Likelihood	**Almost Certain**	**3**	**4**	**6**	**7**	**8**
	Likely	**3**	**3**	**5**	**6**	**7**
	Possible	**2**	**3**	**4**	**5**	**7**
	Unlikely	**1**	**2**	**3**	**4**	**6**
	Rare	**1**	**1**	**2**	**3**	**5**

The risk matrix inherently recognises HILP (high impact low probability) events and gives them a high-risk level ranking so that they receive appropriate attention as described below in Table 58.

Table 59: Management attention to risk rankings

Low	Medium	High	Critical
Risk managed through routine management/internal control procedures	Risk to be reported to relevant manager, may require additional risk treatment actions	Risk to be reported to chief executive and senior leadership team to approve and monitor risk treatment actions	Risk to be reported to the board to approve and monitor risk treatment actions
Levels 1 & 2	**Level 3**	**Level 4 & 5**	**Level 6, 7 & 8**

Risk Treatment and Mitigation Prioritisation

Risks can never be eliminated and therefore an acceptable level of residual risk needs to be determined along with appropriate timeframes for the implementation of risk treatment measures. Often several treatment options are available and each is likely to have different cost, effort and timeframes associated. Furthermore, each treatment option could be more or even less effective than another option. Treatment options are not necessarily mutually exclusive and may be used in combination where appropriate. Table 60 summarises the types of treatment options that should be considered for any risk. These options are ordered by effectiveness for the control of risk.

Table 60: Options for Treatment of Risk

Treatment Options	
Terminate	Deciding not to proceed with the activity that introduced the unacceptable risk, choosing an alternative more acceptable activity that meets business objectives, or choosing an alternative less risky approach or process.
Treat	Implementing a strategy that is designed to reduce the likelihood or consequence of the risk to an acceptable level, where elimination is considered to be excessive in terms of time or expense.
Transfer	Implementing a strategy that shares or transfers the risk to another party or parties, such as outsourcing the management of physical assets, developing contracts with service providers or insuring against the risk. The third-party accepting the risk should be aware of and agree to accept this obligation.
Tolerate	Making an informed decision that the risk rating is at an acceptable level or that the cost of the treatment outweighs the benefit. This option may also be relevant in situations where a residual risk remains after other treatment options have been put in place. No further action is taken to treat the risk, however, ongoing monitoring is recommended.

Good risk management recognises that limited resources are available and that all risks cannot immediately be effectively mitigated. The desired outcome for risk treatment is a low-cost option or combination of options that reaches an acceptable residual risk level within an appropriate timeframe. A low-cost option providing very effective mitigation compared with a higher cost option providing less effective mitigation might be an obvious choice, but deciding between high cost-effective treatments and low cost but less effective risk treatment options may be difficult and requires careful evaluation of all factors involved.

Depending on the magnitude of risk identified a large-scale programme may be initiated to quickly reduce risk. Often asset management related risks will have mitigating solutions that become a part of design standards used on the network. The level of risk will determine if standards are retrospective i.e., applied to shape the existing network rather than only applying to new assets installed.

Effective risk management requires prioritisation of the many risk reduction actions identified and to do this the “greatest risk reduction utilising available resources” is used as a guiding principle. Appropriate resourcing needs to be considered and adjustment of available resources may be required to control risk appropriately. This is explicitly recognised as part of the Health and Safety at Work Act where sufficient resources to reduce hazards “as far as reasonably practicable” must be provided.

Safety in Design

A formal Safety in Design process based on the EEA Safety in Design Guidelines is being introduced into all asset creation projects. PowerNet subscribes to the five key principles of safe design and is

implementing them in all design processes to eliminate or reduce risk as early as possible in the asset life cycle:

- Collaboration – teams and people co-operate to identify project risks and define the implications of the decisions on health and safety. Efforts are coordinated and the best people for the design are utilised
- Accountability – the people doing the design has the accountability as well as the authority to actively promote health and safety from the start of a project.
- Lifecycle view – Hazards and risks that may only manifest later are addressed as early as possible in the asset lifecycle. The emphasis is not only on addressing short term risks.
- Systematic and systemic - Hazard identification, risk assessment and risk control happens throughout the whole design process and is implemented thoroughly, and intentionally and methodically.
- Information transfer and Communication - . There is continual and effective bi-directional communication between the project team and other stakeholders with relevant experience and knowledge. Design and risk control information is correctly documented and disseminated.

6.2. Company related risks (general)

COVID pandemic - Loss of key service providers; business operations disrupted

This risk manifested during 2020 when the COVID-19 virus caused a worldwide pandemic. The probability of this risk occurring was deemed "Rare", but it happened. The risk is now a "Critical" risk. However, in line with Central Government guidelines, Electricity Distribution is an essential service and work needs to continue. The following treatment responses are available:

- Adhere to government guidelines.
- Work to the PowerNet pandemic plan. This includes measures such as working from home, only critical faults and critical maintenance work and providing emergency kits for offices.
- Supply chain management.
  - Assist in identifying critical suppliers and manufacturers so that the manufacture of critical equipment such as poles can continue.
  - Ensure sufficient stock levels of critical items and consumables, including safety equipment such as masks and disposable gloves.
  - Identify key contractors and negotiate availability agreements.
- Contact tracing.

The mitigation measures mostly worked, apart from completing some major projects and some maintenance work. Major projects were delayed by the difficulties in getting imported equipment into New Zealand. Non-critical but nevertheless essential maintenance were postponed and the resultant backlog has not been fully cleared. This has led to underspending in some CAPEX and OPEX categories.

Cyber Security

Cyber security events were detected and intentional damage was prevented by the IT security systems. There is however a notable increase in these types of events.

Industry Regulation

Gaps or breaches industry regulation have been identified as the following.

- Investment – providing business processes that ensure appropriate contracts and guarantees are agreed prior to undertaking large investments.
- Loss of revenue – loss of customers through by-pass or economic downturn could reduce revenue.
- Management contract – failure of PowerNet as EIL's asset manager.
- Regulatory – failure to meet regulatory requirements.
- Resource – field staff to undertake operation, maintenance, renewal, up-sizing, expansion and retirement of network assets.

Table 61: Industry Regulation Risks and Responses Event

	Likelihood	Consequence	Responses
Uncompetitive Return on Investment	Likely	Major	• Cut cost to a level where reliability of supply will not materially deteriorate but will also not improve.
Failure of the Management Contract	Rare	High	• Continue management contract with PowerNet noting that it operates a Business Continuity Plan • PowerNet investment in improving its business management systems and processing
Regulatory breaches	Unlikely	High	• Continue to contract PowerNet to meet regulatory requirements. • Ensure PowerNet has and operates to a Business Continuity Plan.
Inadequate Resource to execute required work	Unlikely	High	• PowerNet utilises internal staff allowing effective planning and management of recruitment training and retention of skilled staff. • Endeavour to provide a reasonably constant stream of work for key external contractors to assist in their continued viability.

6.3. Asset Management Risk

Asset management related risks that have been identified for TPCL have been classified under the categories; physical, safety and environmental, human, external, weather, and corporate; with a summary of the risk assessment under each of these categories is as follows.

The following extract from the corporate risk register indicates risks specifically relating to Asset Management.

Table 62: Asset Management Risks

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Network Performance	**Failure of Asset Lifecycle Management**	Mechanical or electrical failure; ineffective maintenance; ineffective fleet plans; budget constraints; lack of future network planning	Reliability Collapse/fall causing harm Voltage causes harm	Treat	Implement AMMAT improvements; resourcing; fleet plans; business management framework
Network Performance	**Operational systems failure due to breakdown in telecommunications**	SCADA communications has one centralised communications point that all information is passed through.	Loss of SCADA would require resorting to manual oversight of the networks	Treat	3 yr. Project underway to provide further links - due for completion 2023
Network Performance	**Intentional Damage**	Terrorism, theft, vandalism Reputation	Damage to equipment Damage to systems/data Change in network configuration SAIDI/SAIFI Impacts Reputation Impacts	Treat	Programme to replace locks and improve security to be investigated
Network Performance	**Loss of right to access or occupy land**	Risk of assets losing / not having the right to occupy locations (e.g., Aerial trespass, subdivision)	Objection of landowner where line is over boundary Demand for removal of assets and/or legal action	Tolerate	
Operational Performance	**Damage due to extreme Physical Event (i.e., Christchurch earthquake)**	Damage caused by force majeure to our infrastructure or equipment (e.g., floods, earthquakes)	Limited staff, facilities or equipment available	Treat	Completion of seismic strengthening Design of networks to avoid high event probability areas
Operational Performance	**Full sector reputation damage**	Loss of stakeholder confidence due to nationwide issues and concerns with electricity industry or EDB sector specifically	Significant dissatisfaction with electricity industry due to adverse impacts for customers, such as price shock through changes in sector pricing. Could be triggered by electricity shortage, change in pricing methods impacting on specific customer groups	Treat	

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
Operational Performance	**Potential liability for private lines and connections**	Regulatory change Poor historical process/records Fatality with some repercussion for PowerNet - legal advice has not been tested in court	Obligation to maintain assets vested in the network	Treat	Association to ENA and MBIE: *(currently reviewing situation with aim of a consistent industry solution)*
Operational Performance	**Major Contractual Breach**	Breach of contractual obligations in place with key counterparties, resulting in legal action with potential serious financial implications and/or reputational damage	Breach of agreement results in loss of ability to continue to provide the service. This results in a significant reduction in value the business	Treat	
Operational Performance	**Unavailability of critical spares**	Poor future work planning High impact low probability events causing high spares usage Supply chain disruptions	Inability to supply	Treat	Review critical spares process Stocktake critical spares Record spares in Maximo Education of staff on spares process and locations Comparison of existing assets to critical spares (and update with changes to the network)
Operational Performance	**Loss of key critical service provider**	Economic environment Lack of sufficient work to sustain Unexpected inability of contractor to complete work Major health event/pandemic	Inability to build or maintain assets Unable to service existing contracts	Treat	Improved identification of critical suppliers Identify alternative suppliers Diversify the workforce Internalise and grow internal workforce Diversify into new markets (create a larger pool)
Operational Performance	**Major event triggering storm gallery activation**	Damage caused by wind, snow, storm events	Delayed or limited provision of power to consumers Loss of ability to provide power to customers for extended periods	Treat	Develop improved contingency plans for network events
Financial	**Change to EDB Environment**	External decision makers trigger industry disruption and change. Likely to be regulatory intervention in industry structure	Forced amalgamation of EDBs with asset value and sales transaction set/influenced by third parties with	Treat	

Category	Risk Title	Risk Cause	Worst Case Scenario	Treatment	Treatment Plan Summary
		and/or economic return framework	risk of significant shareholder value destruction		
Regulatory Change & Compliance	**Gaps or breaches in Industry regulation**	Changes to the industry environment result in uncertainty of accountability and authority to operate	Ability to operate in part of the industry restricted or removed due to regulatory gap, for example, own / operate new technology and gain value from that opportunity	Treat	
Health & Safety	**Public encountering live assets**	Unexpected public actions affecting our assets or asset integrity affects public safety	Serious injury or fatality Prosecution under H&S Act	Treat	Asset Lifecycle risk management Increase public awareness through various media Asset design and operation
Environmental	**Breaches of environmental legislation**	Failure of assets, oil spill, bunding, hazardous goods breach	Breaches of environmental legislation Cost of rehabilitation	Treat	Design standards take environmental risk into account Asset do not contain hazardous substances or hazardous substances are controlled

Asset management risks are in the categories of Network and Operational Performance, Health & Safety and Environmental. These risks can partly or in full be addressed through the asset management system. A summary of the risk assessment under each of these categories is described in the next paragraphs.

Network and Operational Performance

The following network and operational performance risks were identified and the quantification and treatment responses are summarised in Table 63 and Table 64.

- **Equipment Failures** – equipment failures can interrupt supply or prevent systems from operating correctly, e.g., failure of a padlock could allow public access to restricted areas.
- **Fire** – transformers are insulated with flammable mineral oil and buildings contain combustible materials. Fire could be triggered by internal external sources and will impact electricity supply.

Table 63: Risk Associated with Equipment Failures

Event	Likelihood	Consequence	Responses
33 kV & 66 kV Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by ringed subtransmission or through the distribution network. • All new lines designed to AS/NZS 7000:2010
Power Transformer	Unlikely	Low to medium	• At dual power transformer sites, one unit can be removed from service due to fault or maintenance without interrupting supply. • Continue to undertake annual DGA to allow early detection of failures. • Relocate spare power transformer to site while damaged unit is repaired or replaced.
11 kV Switchboard	Unlikely	Medium	• Annual testing including PD [15]and IR[16]. • Replacement at end of life and continue to provide sectionalised boards. • Able to reconfigure network to bypass each switchboard with use of mobile regulators.
11 kV & 400 V Lines and Cables	Possible	Low	• Regular inspections and maintain contacts with experienced faults contractors. • Provide alternative supply by meshed distribution network.
Batteries	Unlikely	Medium	• Continue monthly check and six-monthly testing. Dual battery banks at critical sites.
Circuit breaker Protection	Unlikely	Medium	• Continue regular operational checks. • Engineer redundancy/backup into protection schemes. • Regular protection reviews. • Mal-operations investigated.
Circuit Breakers	Unlikely	Low	• Backup provided by upstream circuit breaker. • Continue regular maintenance and testing.
SCADA RTU	Unlikely	Low	• Monitor response of each RTU at the master station and alarm if no response after five minutes. • If failure then send faults contractor to restore, if critical events then roster a contractor onsite.
SCADA Master-station	Very Unlikely	Low	• Continue to operate as a Dual Redundant configuration, with four operator stations. This requires both Servers to fail before service is lost. • Continue to have a support agreement with the software supplier and technical faults contractor to maintain the equipment.
Load Control	Unlikely	Medium	• Provide backup between EIL and TPCL ripple injection plants at Invercargill. • Manually operate plant with test set if SCADA controller fails.
Fire	Very Unlikely	High	• Supply customers from neighbouring substations. • Maintain fire alarms in buildings.

The impact of equipment failure is unpredictable, therefore PowerNet provides a central control room which is staffed 24 hours a day. Engineering staff are always on standby to provide backup assistance

15 PD = Partial Discharge, indication of discharges occurring within insulation.

16 IR = Infrared, detection of heat of equipment that highlights hot spots.

for network issues. Contractors provide onsite support for the repair of minor failures. For the repair of medium to large failures or when storms occur, 'on-call' contractors are available.

The following additional network and operational performance risks were identified and their treatment responses are described in the next table.

- **Animals** – could physically connect with overhead conductors (e.g., birds, possums) or cause conductor clashing (e.g., cattle against stays).
- **Third party accidental damage to network** – e.g., car versus pole, over-height loads breaking conductors. The presence of a pole may also increase the damage done to a car and its occupants if the driver veers off the road.

Table 64: Other Network and Operational Performance Risks

Event	Likelihood	Consequence	Responses
Animal	Highly Likely	Low	• Possum guards all poles • Cattle guards, bird spikes as required
Third party accidental	Possible	High (Safety) Low (Network)	• Design (assets, protection settings) to minimise electrical safety consequences of failure • Underground particularly vulnerable areas • Approval process for railway crossings, etc. • Regular inspections for sag etc. • Resource available to bypass and repair.

Health and Safety

- Health and safety risks that were identified are listed below with treatment responses indicated in Table 65: Health and Safety Risks.
- **Accidental public contact with live equipment** – whether through using tall equipment near overhead lines or through excavating near cables.
- **Step and touch** – faults/lightning strikes causing a voltage gradient, across surfaces accessible to the public, that is capable of causing electric shock.
- **Arc flash** – potential for significant injury to staff from a fault on or near equipment they are using/working on.
- **Underground assets** – safety risks amplified by the close proximities and contained space around underground assets.
- **Staff error** - causing worksite safety risk.
- **Historical assets** - not meeting modern safety requirements.
- **Site security** – unauthorised persons approaching live components through unlocked gate etc.

Table 65: Health and Safety Risks

Event	Likelihood	Consequence	Responses
Public Accidental Contact	Possible	High	• Public awareness program – social media, radio, print, signage at high-risk areas • Offer cable location service • Emergency services training • Relocate/underground near high-risk areas e.g., waterways where feasible • Include building proximity to lines in local body consent process

Event	Likelihood	Consequence	Responses
			• Audit new installations for correct mitigation, e.g., marker tape/installation depth/Magslab for cable • Regular inspections of equipment to detect degraded protection of live parts
Step & Touch	Unlikely	High	• Adopt & follow EEA Guide to Power System Earthing Practice in compliance with Electricity (Safety) Regulations 2010
Arc Flash	Very Unlikely	High	• Install arc flash protection on new installations • Mandate adequate PPE for switching operations • De-energise installation before switching where PPE inadequate
Underground	Unlikely	High	• De-energise substation before manual switching within substation
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs • Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met
Staff Error	Possible	High	• Standardised procedures • Training • Worksite audits • Certification required for sub entry, live-line work, etc. • Monitor incidents and investigate root causes
Historical Assets	Possible	Medium to High	• Replace old components with new components meeting current standards: scheduled replacement or replacement on failure, check specifications and replace if risk significant
Site Security	Very Unlikely	High	• Monthly checks of restricted sites • Alarms on underground sub hatches • Standardised exit procedures in 3rd party building • Above ground sub clearances to AS2067 s5 • Design to avoid climbing aids etc.

Environmental

The following environmental risks have been identified and their quantification and treatment responses are presented in the next tables.

High Impact Low Probability (HILP) Events

- **Earthquake** – no recent history of major damage. The November 2004, **7.2** Richter scale quake, 240 km south-west of Te Anau caused no damage to the network. The earthquakes in Christchurch demonstrated that large and unexpected events may occur and these would have a significant impact on the network.
- **Tsunami** – may be triggered by large off shore earthquake.
- **Liquefaction** – post Christchurch's 22 February 2011 **6.3** magnitude earthquake, the hazard of liquefaction as a risk needs to be considered.

Table 66: High Impact Low Probability Risks

Event	Likelihood	Consequence	Responses
Earthquake (>8)	Very Unlikely	High	• Disaster recovery event. • Projects underway to investigate and improve survivability through large seismic events.
Earthquake (6 to 7)	Very Unlikely	Low to High	• Specify so buildings and equipment will survive. • Review existing buildings and equipment and reinforce if necessary.
Tsunami	Very Unlikely	Low to Medium	• Review equipment in coastal areas and protect or reinforce as necessary.
Liquefaction	Very Unlikely	Low to Medium	• Specify buildings and equipment foundations to minimise impact.

Other Potential Environmental Risks

- Oil spills from transformers or oil circuit breakers
- Release of SF6 into the atmosphere

Table 67: Other Environmental Risks

Event	Likelihood	Consequence	Responses
Oil spill (zone sub)	Unlikely	Medium	• Oil spill kits located at some substations for the faults contractor to use in event of oil leak or spill. • Most zone substations have oil bunding and regular checks that the separator system is functioning correctly. • Bunding is installed in the remaining substations as the opportunity arises. • Regular checks of tank condition
Oil spill (distribution transformer)	Possible	Low	• Distribution transformers located away from waterways, etc. • Installations designed to protect against ground water accumulation
SF_6 release	Unlikely	Low	• SF6 storage and use recording and reporting • Procedures for correct handling.
Noise	Unlikely	Medium	• Designs incorporate noise mitigation • Acoustic testing at sub boundaries to verify designs

Event	Likelihood	Consequence	Responses
			• Adhere to RMA and district plans requirements
Electromagnetic fields	Unlikely	Medium	• Adhere to RMA and district plans requirements • Electromagnetic test at sub boundaries to demonstrate requirements met

Weather Related Risks

The following potential weather-related risks have been identified with Table 68 summarising their quantification and treatment responses:

- **Wind** – strong winds that either cause pole failures or blow debris into lines.
- **Snow** – impact can be by causing failure of lines or limiting access around the network.
- **Flood** – experience of 1984 floods has caused Environment Southland to install flood protection works, but still need to consider if similar water levels do occur again.

Table 68: Weather Related risks

Event	Likelihood	Consequence	Responses
Wind	Possible	Low	• Impact is reduced by undergrounding of lines • Design standard specifies wind loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements.
Snow	Unlikely	Low	• Impact is reduced by undergrounding of lines • Design standard specifies snow loading resilience levels. • If damage occurs on lines this is remedied by repairing the failed equipment. • Inspections recognise asset criticality and resilience requirements. • If access is limited then external plant is hired to clear access or substitute.
Flood	Unlikely	Low	• Transformers and switchgear in high risk areas to be mounted above the flood level. • Zone substations to be sited in areas of very low flood risk or elevated to minimise risk.

7. Evaluation of Performance

Details of asset management performance, measurement, evaluation and improvement;

7.1. Progress against Plan

Capital Expenditure

Table 69: Variance between Capital Expenditure Forecast and Actual Expenditure

Capital Expenditure	Forecast 2019/20 ($k)	Actual 2019/20 ($k)	Variance
Consumer Connection	3,385	4,718	39%
System Growth	4,724	3,668	-22%
Asset Replacement and Renewal	12,721	12,968	2%
Asset Relocations	516	209	-59%
Quality of Supply	923	1,240	34%
Legislative and Regulatory	–	–	–
Other Reliability, Safety and Environment	2,836	3,543	25%
Capital Expenditure on Network Assets	**25,939**	**26,346**	**5%**

Capital works was over budget due to;

- Customer Connections – 39% over budget due to continuation of previous financial year rollover of large connection projects that was deferred. Increased number of new connections.
- System Growth – 22% underspend. Delays in the design stage of both Seaward Bush and Kennington projects affected overall spend. The deferment of capital works to accommodate new large consumer connection requiring work re-prioritisation. Details of significant projects expanded below in Table 70.
- Asset Replacement and Renewal – 2% overspend to manage the risk effectively of work identified during inspections - largely focused on pole replacements along with low conductor remedial work and ABS replacements.
- Asset Relocations – 59% under budget. Due to material delivery delays, the Fairlight Regulator relocation was deferred to 2021.
- Reliability, Safety and Environment - 25% over budget. Bluecliffs RAPS over budget to accommodate additional costs for resource consent. Increased scope the Edendale Arcflash upgrade. An increased emphasis on earth upgrades to improve network safety.

Table 70: System growth project expenditure details

Project	Planned Completion	Actual Completion	Reason
OVP-Centre Bush to Mossburn 66kV Line	100%	100% Physical 96% Financial	Construction ahead of schedule and early material delivery. New scope installing 2 x 66kV Isolators for following financial year.
OVP-Dipton Substation Upgrade	100%	98% Physical 86% Financial	Original Scope complete. New scope in 2020/21 FY to install 2 x new 66kV circuit breakers.
OVP Lumsden Substation Upgrade	100%	99% Physical 93% Financial	Project complete, final as-build drawings to complete
Kennington 2nd 33kV Line	80%	40% Physical 78% Financial	Design delays and Construction work delayed in March.
Glenham Transformer Upgrade	30%	0% Physical 5% Financial	Project completion deferred to future years
Gorge Road Transformer Upgrade	30%	12% Physical 38% Financial	Some delays to resources being utilised at major customer connection and transformer upgrade to be completed in 2020/21
22kV Upgrade Athol - Kingston	15%	0% Physical 0% Financial	Project deferred to start 2020/21

Operational Expenditure

Table 71: Variance between Operational Expenditure Forecast and Actual Expenditure

Operational Expenditure	Forecast 2019/20 ($k)	Actual 2019/20($k)	% Variance
Service Interruptions and Emergencies	4,475	4,477	0%
Vegetation Management	1,799	1,592	-12%
Routine and Corrective Maintenance and Inspection	5,351	4,779	-11%
Asset Replacement and Renewal	1,407	641	-54%
Operational Expenditure on Network Assets	**13,032**	**11,489**	**-12%**

Maintenance was under budget due to;

- Vegetation Management – 12% under budget due limited availability of contractors' primary EWP vehicle.
- Routine and Corrective Maintenance and Inspection – 11% under budget due to corrective maintenance being reactive in nature and less work completed.
- Service Interruptions and Emergencies – Overall OPEX expenditure close to budget

Asset Replacement and Renewal – Under budget by 54% due to focus on capital pole replacement rather than minor maintenance.

7.2. Service Level Performance

Reliability

Table 72 displays the target versus actual reliability performance on the network. For the 2019/20 year the overall network performance was below par, with SAIFI 23% above% of target and SAIDI 70% above% target.

Table 72: Performance against Primary Service Targets

	2019/20 AMP Target	2019/20 Actual
SAIFI	2.84	3.50
SAIDI	149.62	255.7

Targets are based on averages over the previous five years and due to the reliability of the network have been set at a level which typically excludes major storms. This, however, means major storm events have the potential to have a significant impact on reliability performance.

Customer Satisfaction

The telephonic customer engagement survey provides feedback enabling us to understand customer satisfaction regarding a range of aspects around their supply services. Statistics are recorded for any customer complaints received. Table 73 shows the 2019/20 results, completed in February 2020, for the service levels that TPCL have set targets for.

Table 73: Performance against Secondary Service Targets

Attribute	Measure	Target 2019/20	Actual 2019/20
Customer Satisfaction on Faults	No impact or minor impact of last unplanned outage. {CES}	>80%	74%
	Information supplied was satisfactory {CES}	>80%	78%
	PowerNet first choice to contact for faults {CES}	>40%	17%
Supply Quality	Number of customers who have made supply quality complaints {IK}	<10	8
	Number of customers who have justified complaints regarding supply quality {IK}	<4	2
Planned Outages	Provide sufficient information {CES}	>80%	99%
	Satisfaction regarding amount of notice {CES}	>80%	98%
	Acceptance of one planned outage every two years lasting four hours on average. {CES}	>50%	64%

{ } indicates information source; CES = Customer engagement survey using independent consultant to undertake phone survey IK = Internal KPIs.

The percentage of customers who were satisfied that their supply was restored within a reasonable amount of time following an unexpected outage was 49%. However 6% indicated that they were unable to recall, which may indicate that the response time was not unsatisfactory enough to stick in their memory.

The number of customers who were satisfied with the information supplied to them when enquiring about an outage was 88%, which is above the target of 80%. However TPCL's good reliability meant that the sample size of persons who had negative feedback about an outage was very small (n=9), which made this result very susceptible to random variation.

Only 54% of customers surveyed indicated that PowerNet would be their first choice to contact if wanting to report or enquire about a fault which is below TPCL's target of 65%. However 7% of respondents said they would not call anyone while a further 8% would take other approaches such a contacting a friend or neighbour. Therefore of those attempting to contact the appropriate authority, about 67% would contact PowerNet, which is considered a satisfactory result.

Performance against the remaining secondary service levels regarding customer satisfaction was better than the targets set for 2016/17.

Network Efficiency

Table 74: Performance against Efficiency Targets

Measure	2019/20 Target	2019/20 Actual
Load factor	> 65%	61.3%
Loss ratio	< 7.0%	5.8%
Capacity utilisation	> 30%	29.2%

Capacity utilisation was slightly below the target while load factor did not quite achieve the target. The loss ratio did achieve the targets.

Load factor reflects the ratio of TPCL's average demand to peak demand and averages around 61%. Transpower's introduction of the Transmission Pricing Methodology has lowered commercial drivers for controlling peak demand having a negative impact on load factor.

Reported losses tend to vary from year to year more than can be explained by changes in operation and network assets. This variation can mostly be attributed to the retailer accrual process. Therefore a longer term average is more likely to be indicative of actual loss ratio and the longer term average is slightly over 5%. New smart meters will allow better analysis and monitoring.

While it is desirable to have a capacity utilisation factor as high as possible, standardisation of transformer sizing, allowance for growth and the unpredictable consumption patterns of some customers means there is a practical and economic limit to how much this factor can be improved. TPCL's capacity utilisation compares well with other similar distribution businesses.

Financial Efficiency

Table 75: Performance against Financial Targets

Measure	2019/20 Target	2019/20 Actual
Network Opex / ICP	250	317
Network Opex / km	1000	1,300
Network Opex / MVA	21,500	25,193
Non-Network Opex / ICP	150	160
Non-Network Opex / km	600	655
Non-Network Opex / MVA	12,900	12,697

Network operational expenditure was 10% under budget and can be attributed as follows:

Service interruptions and emergencies was 22% above budget. Incident response Technical was 35% under budget due to less faults whilst the larger Incident response Distribution budget was 28% over budget due to the nature of the faults encountered, requiring a higher amount of expenditure

Vegetation management was 12% under budget due to limited availability of main EWP vehicle.

Routine and corrective maintenance and inspection was under budget by 11% due to less reactive work identified.

Asset replacement and renewal was 54% under budget due to focus on capital pole replacement rather than minor maintenance

System Operations and Network support 35% under budget due to Insurance Captive that is not yet operational which makes up 21% of the budget.

Business Support was 16% below budget due to the change in allocation methods to ABBA.

7.3. AMMAT Performance

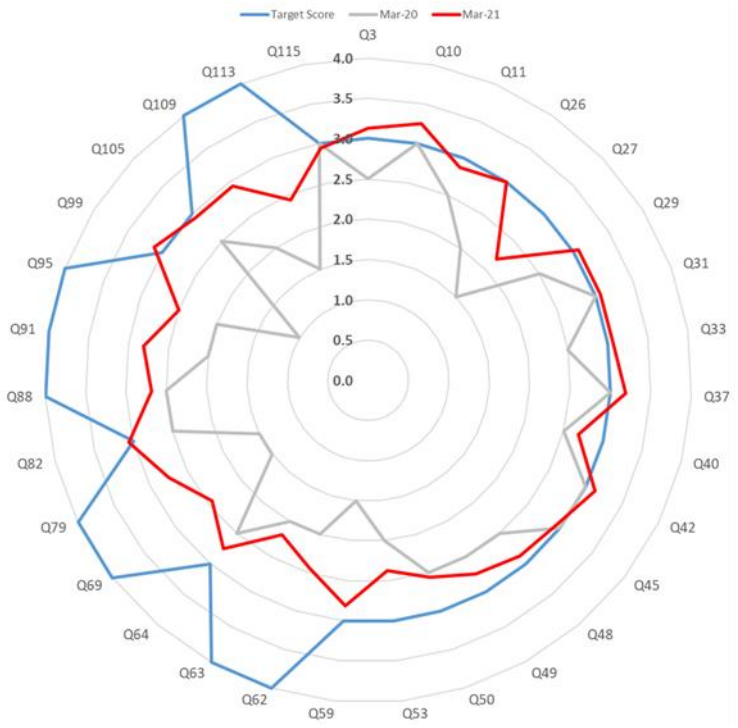
TPCL understands the foundations of good asset management practice and generally endeavours to comply with international best practice as embodied in the ISO5500X suite of standards for Asset Management systems. In addition, and as this is the system still utilised by Commerce Commission, PAS 55 principles are adopted.

The AMMAT is based on a selection of the questions asked in PAS-55 intended to prompt consideration of performance against a number of facets of asset management practice. Each question can be scored from '0' to '4' and each question has a series of answers to describe what is required to achieve each scoring level. Appendix 3 Schedule 13 shows the full AMMAT questions, the scores determined and the maturity description for each question.

In scoring TPCL's asset management practice against the Asset Management Maturity Assessment Tool (AMMAT) scores from '2.2' to '3.3' with an average score of '2.8' were achieved as shown in blue in Figure 46.

All the areas covered in the questionnaire are not of equal importance to an EDB, so target scores were set for each area. These scores are indicated by the blue curve.

TPCL through PowerNet undertook an AMMAT self-assessment for this AMP. The focus was on the changes that had occurred since the 2020 assessment. The red curve shows the result of this assessment. It shows that in most areas we have improved, with the exception of Questions 45 which showed a slight decrease from 3 to 2.9.



Asset management policy	Q3			
Asset management strategy	Q10	Q11		
Asset management plan(s)	Q26	Q27	Q29	Q31
Contingency planning	Q33			
Structure, authority and responsibilities	Q37	Q40	Q42	
Outsourcing of asset management activities	Q45			
Training, awareness and competence	Q48	Q49	Q50	
Communication, participation and consultation	Q53			
Asset Management System documentation	Q59			
Information management	Q62	Q63	Q64	
Risk management process(es)	Q69			
Use and maintenance of asset risk information	Q79			
Legal and other requirements	Q82			
Life Cycle Activities	Q88	Q91		
Performance and condition monitoring	Q95			
Investigation of asset-related failures, incidents and nonconformities	Q99			
Audit	Q105			
Corrective & Preventative action	Q109			
Continual Improvement	Q113	Q115		

Figure 46: TPCL's Asset Management Maturity Assessment Tool Scores

7.4. Gap Analysis and Planned Improvements

AMMAT

For a distribution company of TPCL's size a score of '2' and '3' for many of the asset management functions is considered appropriate. However as PowerNet provides TPCL's asset management services as well as providing this service across other networks, TPCL believes that some improvements are realisable and appropriate. TPCL therefore believes a score of '3' is desirable as a long term goal for each of the AMMAT functions and that improvements made over time would be generally in line with TPCL's asset management and corporate strategies, ultimately supporting the achievement of TPCL's asset management objectives.

Of the 30 questions posed in the AMMAT, nine scores of '3' have been determined across the areas of Asset Management Policy, Asset Management Plans, Contingency Planning, Structure Authority and Responsibilities, Legal and other requirements and Investigation of asset-related failures, incidents and nonconformities. For the remaining questions there is room for improvement. No score was less than 2.

Whilst noting that some scores have improved, the following improvements to asset management practices have been made or are ongoing:

- The Asset Management Information System is being redeveloped to facilitate improved management of maintenance activities.
- Asset Fleet Plans are being developed that will allow improved management of assets over their full life cycle. These plans will be incorporated into the Asset Management Information System.

- A stage gate process for managing major projects has been adapted and will be introduced to improve capital and maintenance project implementation.
- The PowerNet organisational structure has been further refined to enhance the ability to deliver TPCL's asset management objectives.
- The overhead lines inspection process has been an area of continued focus for PowerNet. The process to ensure consistency in inspection results and pole tagging has been implemented.
- Standards are being reviewed and updated to be more risk based.
- A Data Strategy and an Information System Strategy are under development. Key to these strategies is recognising and agreeing that the computerised asset management information system (MAXIMO) will be the single source of truth around assets. Further improvements to the system are being implemented including:
    - Including a Risk Management module into the system.
    - Expanding work scheduling to more systematically and efficiently schedule and track asset maintenance activities to additional asset types.
    - Developing more compatible units to allow standardisation common asset types including cost by materials and labour to enable efficient costing and scheduling of future work.
    - Integration of TPCL's financial management system to efficiently track costs supporting compatible units and understanding whole of lifecycle costs for these assets.
    - Rolling out field devices to operational staff that will allow the direct capturing of data from the field. This also includes automating the risk management framework used in works by field staff.

Implementing a new drawing management system that will allow access to drawings from the field.

Developing and implementing a standard and specification to ensure that contractors deliver the expected work quality.

Implementing a system to keep everybody abreast of legal, regulatory and statutory requirements.

Capital and Maintenance Works

The initiatives above will improve efficiency for capital and maintenance project delivery and support consistent performance against delivery TPCL's AWP.

In addition, TPCL's amalgamation of TPCL's network management company PowerNet and its previous field service contracting companies has improved relationships and communication between planning and field staff. More efficient work practices are being realised; and are expected to continue. The amalgamated company PowerNet has also employed additional technical field staff to extend the in-house field services concept to further realise efficiencies. This should help increase productivity and with some additional resource TPCL should be better placed to deliver the planned projects.

Long term relationships with external contractors are being maintained so they can more confidently build their resources and personnel. This will allow more work to be completed and ensure a resource for future years.

Reliability

TPCL will look to control the impact of events that might incur large customer-minute totals primarily by increasing the number of remotely controlled devices on the network to speed isolation of faulty sections and restoration of supply to healthy sections. The completion of the network automation project will achieve a significant improvement in the network's reliability.

TPCL's network management company PowerNet will work to retain experienced field services staff and maintain long term relationships with external contractors so quality personnel with sufficient network familiarity are available for efficient restoration of supply.

Regular network inspections will be continued and critical items will be acted on as they are identified. Also data capture and condition assessment will be increased above reactive maintenance practices to increase knowledge of the assets and their condition to enable better planning based on more accurate and comprehensive asset data. Again the initiatives noted as improvements under the AMMAT will assist with the improvement of reliability by enhancing TPCL's maintenance practices.

In the long term, network reliability will be difficult to maintain due to the lack of incentive to invest in network reliability initiatives caused by revenue constraints.

Efficiency

Load factor is average compared to other similar EDB's and no specific improvements are targeted. The introduction of additional smart meters in future years is expected to provide some additional leverage to influence customer's consumption behaviour.

Losses and capacity utilisation are not specifically being targeted for improvement except for selecting efficient and optimally sized assets when required for network development or replacements.

8. Capability to Deliver

TPCL succeeds in delivering when the network development and maintenance plans are achieved on time and to budget while achieving service level targets from the present time to the long term. To achieve successful delivery TPCL must have sufficient staffing (planning, management, field services) and financial resources available along with having appropriate systems and processes in place.

8.1. Systems and Processes

The core of TPCL's asset management activities lie with the detailed processes and systems that reflect TPCL's thinking, manifest in TPCL's policies, strategies and processes and ultimately shape the nature and configuration of TPCL's fixed assets. The hierarchy of data model shown in Figure 47 describes the typical sorts of information residing within TPCL's business (including in PowerNet employees brains).

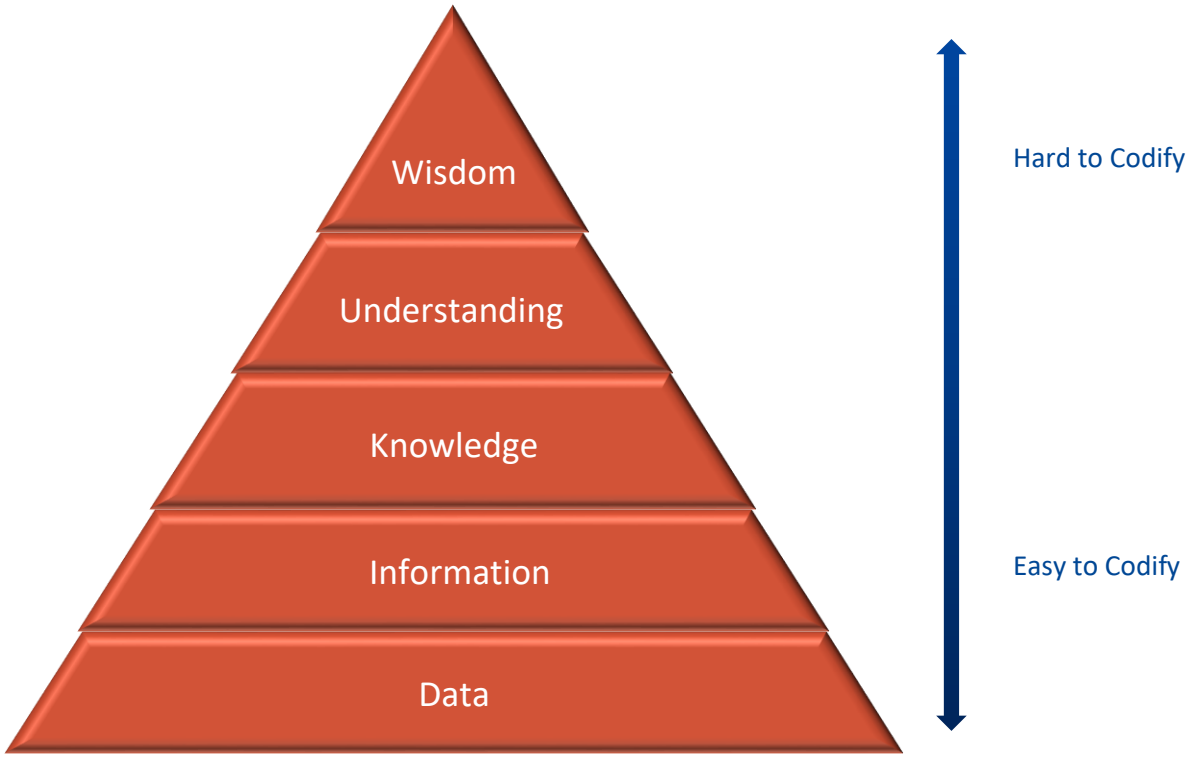


Figure 47: Hierarchy of Data

- The bottom two layers 'Data' and 'Information' of the hierarchy tend to relate strongly to TPCL's asset and operational data and the summaries of this data that form one part of TPCL's decision making.
- The middle layer 'Knowledge' tends to be more broad and general in nature and may include such things as technical standards that codify accumulated knowledge into a single useful document.
- The top two layers 'Understanding' and 'Wisdom' tend to be very broad and often quite fuzzy. It is at this level that key organisational strategies and processes reside. As indicated in Figure 47 it is generally hard to codify these things, hence correct application is heavily dependent on skilled and experienced people.

Asset Management Systems

TPCL has access to a variety of PowerNet owned information management tools which capture asset data and can be used to aggregate this data into summary information. From this information TPCL has a great deal of knowledge about almost all of the assets; their location, what they are made of, generally how old they are and how well they can perform. This knowledge will be used for either making decisions within TPCL's own business or assisting external entities to make decisions.

The decision making process involves the top two levels of the hierarchy, understanding and wisdom, which tend to be broad and enduring in nature. Although true understanding and wisdom are difficult to codify, it is possible to capture discrete pieces of understanding and wisdom and then codify them into such documents as technical standards, policies, processes, operating instructions, spreadsheet models etc. This is called knowledge and probably represents the upper limit of what can be reasonably codified.

Accurate decision making therefore requires the convergence of both information and (a lot of) knowledge to yield a correct answer. Deficiencies in either area (incorrect data, or a failure to correctly understand issues) will lead to wrong outcomes. The roles and interaction of each component of the hierarchy are incorporated in Figure 48 which provides a high level summary of TPCL's asset management processes and systems.

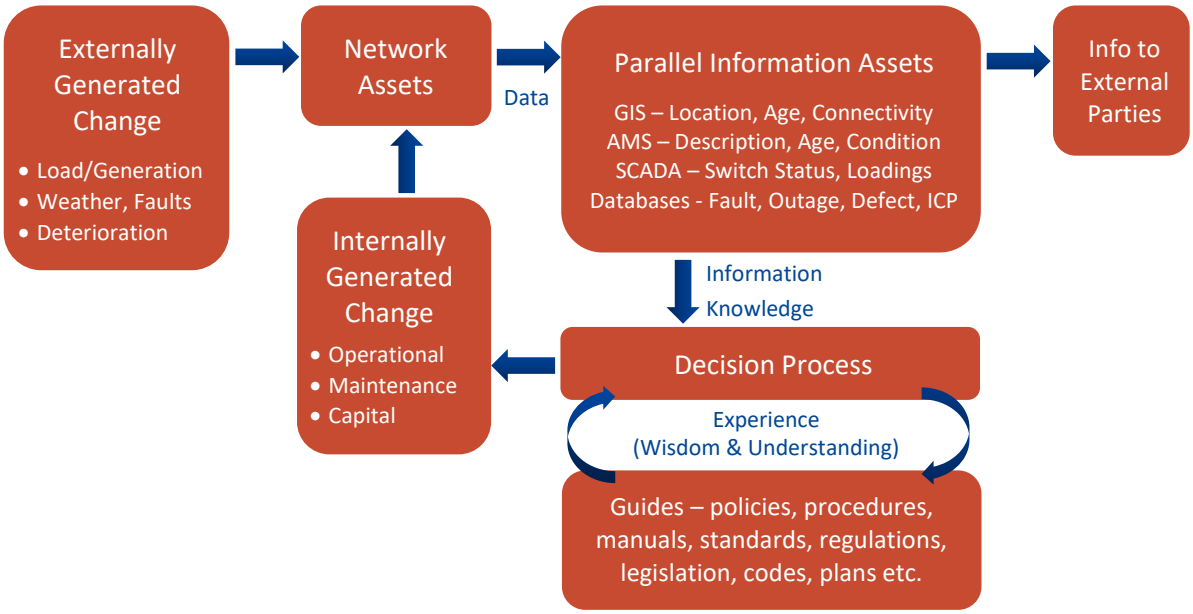


Figure 48: Key information systems and processes

Processes and Documentation

TPCL's key processes and systems are based around the key lifecycle activities defined in Figure 48, which are based around the AS/NZS9001 Quality Management System. The processes are not intended to be bureaucratic or burdensome, but are rather intended to guide TPCL's decisions toward ways that have proved successful in the past (apart from safety related procedures which do contain mandatory instructions). Accordingly these processes are open to modification or amendment if a better way becomes obvious.

The asset management processes are documented and grouped in the following categories with a complete list provided in Appendix 1:

- Operating Processes and Systems
- Maintenance Processes and Systems
- Renewal Processes and Systems
- Up-sizing or Extension of Processes and Systems
- Retirement Processes and Systems
- Performance Measuring Processes
- Other Business Processes

Some processes are prescribed in external documents (such as the information disclosure determination which this AMP is required to comply with) and as such they are not copied onto internal documentation. Processes are often embedded within asset management tools including external requirements such as the need to produce network reliability statistics for disclosure being embedded within the outage management database.

Documents and Control Reviews

Each document is controlled by an owner at management level who is given responsibility for the documents review and update. The documents are reviewed periodically (which includes review of the underlying processes that have been documented) to ensure they are kept up to date and incorporate any changes that have been identified as necessary. Lean Management practices have recently been introduced to refine business and asset management processes with the changes identified ultimately reflected in documented procedures.

Once updates have been finalised they are approved by the controlling manager and all staff are notified by email and where necessary by placement on notice board and direct training and communication to individuals affected.

External audits of specific systems and processes are also conducted. Current external audits include;

- Public Safety Management System (PSMS) (AS/NZS 7901 compliance)
- Occupational Health and Safety Management (AS/NZS 4801 compliance)
- Worksite safety audits (completed by Network Compliance Ltd)
- AMMAT review
- AMP format and compliance review
- Spend forecast assessment
- Spend approval process review

Asset Management Tools

PowerNet maintain and utilise a number of software based tools to efficiently and effectively manage data and knowledge for TPCL's network assets.

The computerised **Asset Management System (AMS), Maximo,** stores TPCL's assets descriptions, details, ages and condition information for serial numbered components. It also provides work scheduling and asset management tools with most day to day operations being managed through the AMS. Maintenance regimes, field inspections and customers produce tasks and/or estimates, that are

sometimes grouped and a 'work order' issued from the AMS which is intricately linked to the financial management system. This package tracks major assets and is the focus for work packaging and scheduling. The individual assets that make up large composite items such as substations are managed through the AMS in conjunction with other more traditional techniques such as drawings and individual test reports. The Maximo software package is utilised as TPCL's AMS. Maximo is considered suited to TPCL's needs, providing sufficient functionality and helping streamline administration of TPCL's maintenance practices.

An Intergraph based **Geographic Information System (GIS)** is utilised to store and map data on individual components of distributed networks. The GIS focuses primarily on geographically distributed assets such as cables, conductors, poles, transformers, switches, fuses and similar items and provides asset description, location and age information for each asset. Locational data is used to provide mapping type displays of existing equipment for planning network upgrades, extensions and maintenance scheduling. It allows these plans to account for distance and travel time and any other factors influenced by the geographic distribution of the assets. Electrical connectivity, capacity and ratings also form a crucial data set stored in the GIS which assists the analysis of the networks ability to supply increasing customer load or determine contingency plans.

Export of data from the GIS into **Load Flow and Fault Analysis Software** allows modelling of the network. This helps predict network capability in the existing arrangement and in future "what if" scenarios considered as planning options as well as determining fault levels to assess safety and effectiveness of protection and earthing systems. Two software packages PSS Adept and Cyme are used to perform this analysis for TPCL.

The **Supervisory Control and Data Acquisition (SCADA)** system provides real time operational data such as loadings, voltages, temperatures and switch positions. It also provides the interface through which PowerNet's System Control staff can view the data through a variety of display formats and remotely operate SCADA connected switchgear and other assets. Historical data is stored and provides a reference for planning. For example network loading can be downloaded over several years allowing growth trends to be determined and extended to forecast future loading levels.

Monthly reports out of the **Finance One (F1)** financial system provide recording of revenues and expenses for TPCL line business unit. Project costs are managed in PowerNet with project managers managing costs through the AMS system. Interfaces between F1 and the AMS track estimates and costs against assets.

Outage, Fault and Defect Databases are populated by the System Control staff as information is reported by field staff or via the faults call centre to ensure efficient tracking of operational issues affecting network service levels.

- The faults database logs all customer initiated calls reporting power cuts or part power to store reported information and contact details. Calls are therefore able to be tracked to ensure effective response and restoration.
- The outage database logs outage data used to provide regulatory information and statistics on network performance. As such data capture is in line with regulatory focuses so therefore excludes LV network outages. Reports from this system are used to highlight poorly performing feeders which can then be analysed to determine maintenance requirements or if reliability may be enhanced by other methods. Monthly reports are provided to TPCL board for monitoring, together with details of planned outages.

- Asset defects are captured in another database for technical asset issues which don't have an immediate impact on service levels but have the potential to if not responded to. Defects are tracked in this database and scheduled for remediation.

The **Condition Assessment Database** tracks the results of routine overhead line inspection rounds and is used as a basis for assigning line repair/renewal work. Severely deteriorated structures are marked as red-tagged and are prioritised for repair, and low conductor spans are also marked for a heightened priority. The Condition Assessment Database is being replaced as part of an overhaul of line inspections on all PowerNet-managed networks. A project is underway to allow Maximo to house the inspection information and will permit the recording of repairs and will allow more precision in reliability analysis.

An additional class of data (essentially commercial in nature) includes such data as customer details, consumption and billing history resides in **PowerNet Connect**. This interfaces with the National Registry to provide and obtain updates on customer connections and movements. Customer consumption is monitored by PowerNet Connect which also receives monthly details from retailers and links this to the customer database.

Data Control, Improvement and Limitations

TPCL's original data capture emphasised asset location and configuration and was used to populate the GIS, but didn't include a high level of asset condition. As part of this original data capture the company developed a field manual of drawings and photos to minimise subjectivity. Records and drawings have been used to apply an age but 56% of poles had no supporting information. Due to old poles not having a manufacture date affixed, it is very difficult to obtain the actual age to update GIS. Options have been considered to get ages measured for the un-dated poles but no economic methodology has been found, and condition data is considered to be more useful in determining replacement timeframes.

Almost all GIS data entered for assets is standardised and selected from lists to ensure quality of data entry and for all other data, for example electrical connectivity, thorough processes, peer reviews and well trained staff are used to ensure data entry quality is very good. Key process improvements will include more timely as-builts with PowerNet staff taking GPS[17] coordinates for poles and use of scan-able forms for data input (Teleform system).

Data for the AMS is collected by the Network Equipment Movement (NEM) form that records every movement of serial numbered assets. Some updating of data is obtained when sites are checked with a barcode label put on equipment to confirm data capture, and highlight missed assets. About 20 percent of the network (by length) is condition assessed each year to update asset condition data (noting that asset condition is continually varying), and any discovered details are corrected.

Further improvements to the AMS are continually being undertaken to allow additional asset details to be captured which were historically captured in spreadsheets; especially the addition of condition based indicators to assist in making better asset management decisions. Data validation and completeness controls are also being added over time to prevent new assets being created without all required data being captured.

[17] GPS = Global Positioning System, a device that uses satellites and accurate clocks, to measure the location of a point.

Assets are assigned a unique reference common to both the GIS and AMS. Where asset data is common to both systems it will be input into one system (deemed the master for that data) and automatically copied to the other to ensure consistency. Other systems also have some degree of interface for copying across common data such as customer data residing in both the ICP database and in GIS and referenced by the common ICP number. However apart from these data copying interfaces and for the most part, these tools do not interact directly, with staff pulling together information from the necessary tools for their use as part of their asset management activities.

The SCADA system and monitoring completeness and accuracy is excellent at zone substations as it is critical for both safety and reliability of the network as it is used for the day to day operation of the network. More field devices are being added to SCADA for remote monitoring and operation.

Other data repositories have very good data quality with these database systems controlling data entry through drop down lists and validation controls. Modifications may be made from time to time to better align with maintenance processes as they evolve.

Table 76 provides a summary for the completeness of TPCL's data.

Table 76: Knowledge Completeness

System	Parameter	Completeness	Notes
GIS	Description	Good	Some delays between job completion and GIS update, some cable size/types unknown
GIS	Location	Excellent	Some delays between job completion and GIS update
GIS	Age	Poor	Pole ages not available for large percentage poles
Condition Assessment Database	Condition	Okay	Regular inspections but some subjectivity and condition data not updated with repair
AMS	Description	Okay	Some delays between job completion and Maximo update
AMS	Details	Okay	Some delays between job completion and Maximo update
AMS	Age	Okay	Missing age on old components, mix of installation and manufacturing dates used as age estimate
AMS	Condition	Poor	Some condition monitoring data e.g.DGA and earthing data) in the AMS. Other data not consolidated in a single system.
SCADA	Zone Substations	Excellent	All monitored
SCADA	Field Devices	Good	Monitoring and automation increasing

8.2. Funding the Business

TPCL's business is funded from the revenue received from their customers and through a wide range of internal processes, policies and plans, the company converts that funding into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability, security and supply quality that customers want. This business model is shown in Figure 49.

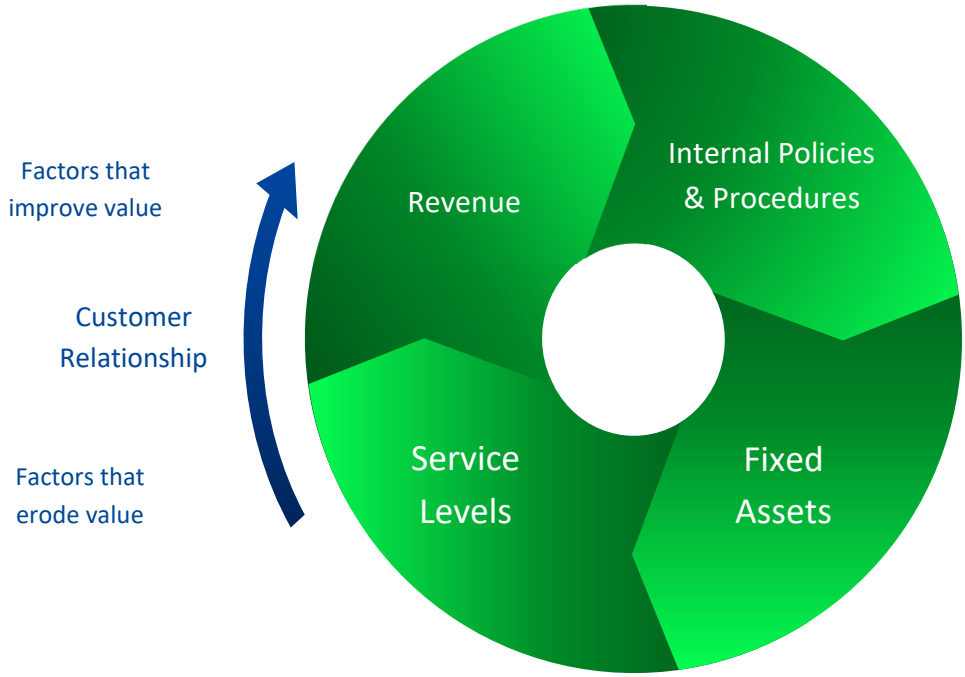


Figure 49: Customer Interface Model

Revenue

TPCL's revenue comes primarily from the retailers who pay for the conveyance of energy over TPCL's network but also from customers providing contributions for the uneconomic part of works. Revenue is set out in a "price path", aligned to determinations by the commerce commission for regulated networks (noting that TPCL is exempt from the "price path" due to 100% consumer ownership)

In regard to funding new assets (i.e. beyond the immediate financial year) TPCL has considered the following approaches:

- Funding from revenue within the year concerned
- Funding from after-tax earnings retained from previous years
- Raising new equity (very unlikely given the current shareholding arrangement)
- Raising debt (which has a cost, and is also subject to interest cover ratios)
- Allowing Transpower to build and own assets which allows TPCL to avoid new capital on its balance sheet, but perhaps more importantly also allows TPCL to treat any increased Transpower charges as a pass-through cost

Expenditure

Work is done to maintain the asset value of the network and to expand or augment to meet customer demands.

Influences on the Value of Assets

An annual independent telephone 'Customer Engagement Survey' is undertaken in September each year and consistently indicates TPCL's customer's price-quality trade-off preferences are as follows:

- A large majority are not willing to pay $10 per month more in order to reduce interruptions
- A very small minority are willing to pay $10 per month more in order to reduce interruptions
- A small minority feel they don't know or are unsure of price-quality trade-offs

In response TPCL's asset value should either remain about the same or be allowed to decline in a controlled manner (and knowing how to do this is obviously a complex issue). However this presents TPCL with the dilemma of responding to customers wishes for lower cost supply in the face of a "no material decline in SAIDI" requirement and in fact revenue incentives to improve reliability. Factors that will influence TPCL's asset value are shown in Table 77 below:

Table 77: Factors influencing TPCL's asset value

Factors that increase TPCL's asset value	
Addition of new assets to the network	Removal of assets from the network
Renewal of existing assets	On-going depreciation of assets
Increase in value of the network assets through the revaluation process	Reduction in value of the network assets through the revaluation process

At a practical level TPCL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

Depreciating the Assets

The accounting treatment of using straight-line depreciation doesn't strictly model the decline in service potential of an asset. It may well quite accurately model the underlying physical processes of rust, rot, acidification, erosion etc., but an asset often tends to remain serviceable until it has rusted, rotted, acidified, or eroded substantially and then fails quickly. Straight-line depreciation does, however, provide a smooth and reasonably painless means of gathering funds to renew worn out assets. This will be particularly important as the "bow wave" of asset renewals (particularly lines) approaches.

8.3. Staff and Contracting Resources

Each item or project making up the AWP is carefully considered as to the man hours required using the experience gained over many years of network management. The works plan as a whole is then considered to ensure that it is realistic with the resources expected to be available and any adjustments can be made. Low priority work may be delayed short term where a commitment to increase staff or contractor numbers has been made such that the necessary works plan will not fall behind. It is important that the AWP "smooths" the year to year work volumes required (to the extent possible acknowledging appropriate risk controls) to provide a relatively constant work stream.

PowerNet's internal field services is a great benefit in ensuring a longer term approach may be taken to resourcing. This means staff numbers can be increased with added confidence that they will be fully utilised in future years given the long term plans developed. Working closely with TPCL's contractors is also an important part of the AWP development process, carefully communicating the detailed works plan and getting commitment that sufficient resources will be available for the year ahead. The future works plan is also communicated so that contractors can confidently commit to hiring extra staff where appropriate, recognising that TPCL's development and maintenance requirements are on-going into the future.

Appendix 1 – Policies, Standards and Procedures

Operating Processes and Systems

Commissioning Network Equipment	NMPR-100
Network Equipment Movements	PNM-063
Planned Outages	NMPR-115
Network Faults, Defects and Supply Complaints	NMPR-125
Major Network Disruptions	PNM-069
Use of Operating Orders (O/O)	NMPR-140
Control of Tags	NMPR-145
Access to Substations and Switchyards	NMPR-010
Operating Authorisations	NMPR-040
Radio Telephone Communications	NMPR-020
Operational Requirements for Live Line Work	NMPR-160
Control of SCADA Computers	PNM-083
Operating Near Electrical Works	NMPR-170
Customer Fault Calls/Retail Matters	NMPR-175
Site Audits	QYPR-010
Meter/Ripple Receiver Control	NMPR-005

Maintenance Processes and Systems

Transformer Maintenance	NMPR-030
Defect Submission and Retrieval from the NEDeRS Database	PNM-066
Control of Network Spares	PNM-097
Maintenance Planning	PNM-105
Network Overhead Lines Equipment Replacement	PNM-106
Earth Tests	PNM-133

Other maintenance is to manufacturers' recommendations or updated industry practise.

Renewal Processes and Systems

Network Development	PNM-113
Design and Development	PNM-114

Up-sizing or Extension Processes and Systems

Processing Installation Connection Applications	PNM-123
Network Development	PNM-113
Design and Development	PNM-114
Easements	PNM-131

Retirement Processes and Systems

Disconnected and/or Discontinued Supplies	NMPR-240

Performance Measuring Processes

These processes are embedded within, and controlled by, the outage, faults and defects databases.

Other Business Processes

In addition to the above processes that are specific to life cycle activities, TPCL has a range of general business processes that guide activities such as evaluating tenders and closing out contracts:

Setting Up the Project	PNM-010
Tendering	NMPR-045
Progressing the Project	PNM-020
Construction Approval	NMPR-110
Materials Management	PNM-030
Project Control	PNM-035
Project Close Out	PNM-040
Customer Satisfaction	QYPR-050
Internal Audits	QYPR-085
Drawing Control	NMPR-015
Network Operational Diagram/GIS Control	NMPR-180
Control of Operating and Maintenance Manuals	PNM-093
Control of External Standards	QYPR-005
Control of Power Quality Recorders	NMPR-195
Quality Plans	NMPR-080
Contractor Health and Safety	HSST-010
Network Accidents and Incidents	HSST-015
Design and Development	PNM-114
Network Purchasing	PNM-115
Network Pricing	PNM-117
Customer Service Performance	PNM-119
Incoming and Outgoing Mail Correspondence	PNM-129
Setting Up the Project	NMPR-010

Appendix 2 – Customer Engagement Questionnaire

PowerNet Customer Engagement

Residential: Can I speak to " insert name " or the person mainly or jointly responsible for paying the electricity account?

Business: Can I speak to the person mainly or jointly responsible for paying the power bill or making decisions about power supply for "insert company name"

My name is ....Calling from Research First on behalf of PowerNet. We are conducting a survey to help PowerNet deliver the right levels of service to its customers and plan effectively for your future needs.

The survey will take about 15 minutes and you will be entered in a draw to win <one of 5 $50 grocery vouchers>

Great, I just have to check if you are eligible:

S1. Are you a PowerNet staff member, or are any of your immediate family a PowerNet staff member?

If yes - I am sorry but you are unable to complete the survey but thank you for time.

If no – Great. We will be linking your responses to your customer number (ICP) this is just to help with analysis. I will start with some general questions about PowerNet...

<INTERVIEWER NOTES: PHONE NUMBERS HAVE BEEN SUPPLIED BY POWERNET FROM THE CUSTOMER DATABASE. WE WILL NOT USE NUMBERS FOR ANY OTHER PURPOSE. RESPONDENTS CAN CALL POWERNET ON +64 3 211 1899 WITH ANY QUERIES)

A	Do you live in a rural area or in a town?
	○ Rural (country)
	○ Town (urban)

SECTION 1: Awareness and Perceptions of Performance

1.	Have you heard of PowerNet?
	○ Yes – Q2
	○ No – Q3

2.	Where have you most recently seen or heard about PowerNet? <do not prompt> <route to 3 except if Facebook mentioned>
	○ Billboard
	○ Sponsorship – St John
	○ Sponsorship – Tour of Southland
	○ Sponsorship – other
	○ Website
	○ Facebook page – Go to Q4
	○ Logos on vehicles
	○ Radio ads
	○ Newspaper ads
	○ Other specify

3.	Were you aware that PowerNet has a Facebook page?
	○ Yes
	○ No

	PowerNet is your local electricity network management company. It maintains the local electricity lines and substations that supply power to your premises for <insert retailer from sample frame: EIL Electricity Invercargill Limited, ONJV OtagoNet Joint Venture, TPCL The Power Company Limited>.

4.	On a scale of 1 to 5 where 1 = 'very poor', 2 = 'poor', 3 = 'neutral', 4 = 'good', and 5 = 'very good', how would you rate PowerNet's performance on the following aspects over the last 12 months? <allow don't know>						
		Very poor	Poor	Neutral	Good	Very good	Don't know
	Caring for customers	1	2	3	4	5	6
	Supporting the community	1	2	3	4	5	6
	Being safety conscious	1	2	3	4	5	6
	Efficiency in service response	1	2	3	4	5	6

5.	On the same scale of 1 to 5, how would you rate the reliability of your power supply?						
		Very poor	Poor	Neutral	Good	Very good	Don't know
	Reliability of power supply	1	2	3	4	5	6

6.	And how satisfied are you with that reliability? Again, use a 1 to 5 scale where 1= very dissatisfied, 2= dissatisfied, 3= neutral, 4= satisfied, 5 = very satisfied.						
		Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied	Don't know
	Satisfaction with reliability	1	2	3	4	5	6

7.	<If coded 1 or 2 at Q5> What is the main reason for your dissatisfaction
	Open comment

SECTION 2: Planned Interruptions to Service

	To allow time for essential maintenance and upgrades all network companies have to plan interruptions to services. Currently, PowerNet plans one interruption to your power supply every two years. The average length of time for an interruption is 4 hours.

8	Given the length of time for a planned interruption would be around 4 hours, what length of time between interruptions do you think is reasonable? <read out single code>
○	More than 1 per year
○	1 per year
○	1 every 2 years
○	1 every 3 years
○	1 every 4 years
○	1 every 5 years
○	No interruptions
○	Don't know
○	Don't care

9	Which of the following options would you prefer?
O	Retain the current plan: 1 interruption of 4 hours every 2 years
O	Have more frequent interruptions but of shorter duration
O	Have less frequent interruptions but of a longer duration
O	Don't know <do not prompt>

10	Would you prefer planned interruptions to take place at a certain time of day?
O	Yes - mornings
O	Yes - afternoons
O	Yes – evenings
O	Yes – overnight
O	No – it does not matter

11	Would you prefer planned interruptions to take place on a weekday or over the weekend?
O	Weekdays
O	Weekends
O	It does not matter

12	Would you prefer planned interruptions to take place at a certain time of year? <multicode>
O	Autumn
O	Winter
O	Spring
O	Summer
O	It does not matter
O	Other specify

SECTION 3: Communications – Planned Interruptions

13	Have you received advice of a planned electricity interruption during the last 6 months?
O	Yes – Q14
O	No – Q19
O	Don't know – Q19

14	Can you remember how much notice you were given?
O	1-2 day -Q15
O	3-4 days -Q15

14	Can you remember how much notice you were given?
○	5-6 days -Q15
○	1 week -Q15
○	2 weeks -Q15
○	More than 2 weeks -Q15
○	Don't know – Q16

15	Do you feel that you were given enough notice of this planned interruption?
○	Yes - Q17
○	No - Q16
○	Don't know - Q17

16	How much notice would you like to be given?
○	1-2 day
○	3-4 days
○	5-6 days
○	1 week
○	2 weeks
○	More than 2 weeks

17	Were you satisfied with the amount of information given to you about this planned interruption?
○	Yes – Q19
○	No - Q18
○	Don't know – Q19

18	What additional information was needed
	Open comment

19	How would you prefer to be notified about planned interruptions? <do not prompt, single code 1st mention>
○	Post
○	Email
○	Facebook
○	Phone call
○	Text
○	App

19	How would you prefer to be notified about planned interruptions? <do not prompt, single code 1st mention>	
	○	Other specify

SECTION 4: Unplanned Interruptions

	Unplanned power outages and faults can be caused by any number of events, from a vehicle hitting a pole, to lightning strikes, trees falling over the power lines, or even vandalism.

20	Who would you telephone in the event of the power supply to your home being unexpectedly interrupted? <do not prompt>	
	○	PowerNet
	○	Retailer/Power company
	○	Local government
	○	Other
	○	No-one

21	Were you aware that PowerNet has a call free 0800 faults number?	
	○	Yes
	○	No
	○	Don't know

22	Can you recall when the last unexpected interruption to your power supply was?	
	○	Yes – In the last week – Q23
	○	In the last month – Q23
	○	2<3 months ago – Q23
	○	3<6 months ago – Q23
	○	More than 6 months ago – Q28
	○	Never had an unexpected interruption to power at this address – Q28
	○	Don't know – Q28
		Don't care – Q28

23	Do you recall how long your most recent power cut lasted?	
	○	Under a minute/it just flicked off and back on
	○	1<30 minutes
	○	30min < 1 hour

23	Do you recall how long your most recent power cut lasted?
	○ 1<2 hours
	○ 2<3 hours
	○ 3<4 hours
	○ More than 4 hours
	○ Don't know

24	On a scale of 1 to 5 where 1 is no impact at all, 2 is minor impact, 3 is neutral, 4 is moderate impact and 5 is major impact, how much impact did your last power cut have on you?
	○ No impact
	○ Minor impact
	○ Neutral
	○ Moderate impact
	○ Major impact
	○ Don't know

25	Did you call your power company or network provider when the supply was interrupted?
	○ PowerNet – Q26
	○ Retailer/Power company – Q28
	○ Local government – Q28
	○ No-one – Q28
	○ Other – Q28
	○ Don't know/can't remember – Q28

26	On a scale of 1 to 5 where 1 = 'very dissatsfied', 2 = 'dissatisfied', 3 = 'neutral', 4 = 'satisfied', and 5 = 'very satisfied', how satisfied were you with...?					
			Very dissatisfied	Dissatisfied	Neutral	Satisfied	Very satisfied
		The system you had to use to get information	1	2	3	4	5
		The information that was provided	1	2	3	4	5

If coded 1 or 2 at Q26 – go to Q27

If coded 3,4,5 at Q26 – go to Q28

27	<If coded 1 or 2 at Q26> What could be done to improve this process	
	O	Open comment
	O	Don't know

28	In the event of an unexpected interruption to your electricity supply, what do you consider would be a reasonable amount of time before electricity supply is restored to your home?	
	O	Under 30 minutes
	O	30min < 1 hour
	O	1<2 hours
	O	2<3 hours
	O	3<4 hours
	O	More than 4 hours
	O	Don't know

29	In the event of an unexpected interruption to your electricity supply, what is the most important information that you wish to receive? <do not prompt, multicode>	
	O	Accurate time power will be restored
	O	Reason for fault
	O	That they know the problem and that it is being fixed
	O	Other specify
	O	No information required

<NEED TO TEST WHICH OF THE FOLLOWING 2 QUESTIONS WORKS BEST>

30 b	PILOT: Currently there is an average of one interruption to power supply due to faults every 2 years IF different options were available. Which of these scenarios would you prefer?	
	O	Reduce the number of interruptions but pay a bit more per month
	O	Increase the number of interruptions and pay a bit less each month
	O	Keep the numbers of interruptions and prices the same
	O	Don't know

Section 5: Evolving Technology

	PowerNet needs to plan for future energy use, so they are interested in understanding what people know about new technologies.

31	Which of the following technologies are you aware of?
	○ Solar/photovoltaic panels
	○ Battery storage
	○ Electric vehicles
	○ Home energy management systems
	○ None of these

32	<remove codes not marked at Q31> Do you have any of these now, or are you considering purchasing them in the next year, 5 years or 10 years?					
			Already have	Considering in next year	Considering in next 5 years	Considering in next 10 years	No plans to purchase
		Solar/photovoltaic panels	1	2	3	4	6
		Battery storage	1	2	3	4	6
		Electric vehicles	1	2	3	4	6
		Home energy management systems	1	2	3	4	6

33	<if coded 1 at electric vehicles Q32> When do you **normally** charge your Electric vehicle
	○ Overnight
	○ During the day
	○ Other specify

34	<if coded 1 at electric vehicles Q32> If it was cheaper to charge overnight would you change the time you charge?
	○ Yes
	○ No
	○ Don't know

35	<from Q33 – all codes 2,3,4> What would prompt you to purchase each of the following...? <do not prompt>					
			Drop in purchase price	Heightened environmental	Reasonable pay back period	Other specify	

35	<from Q33 – all codes 2,3,4> What would prompt you to purchase each of the following...? <do not prompt>					
	Solar/photovoltaic panels	1	2	3	4	6
	Battery storage	1	2	3	4	6
	Electric vehicles	1	2	3	4	6
	Home energy management systems	1	2	3	4	6

Section 6: Final comments

36	Finally, are there any other comments you would like to make about PowerNet services?
	○ No comment
	○ Happy with service
	○ Other specify

That concludes this survey.
Just to remind you my name is from Research First. Thank you very much for your time and the information you have provided.

Appendix 3 – Disclosure Schedules

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2021 – 31 March 2031**

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).

This information is not part of audited disclosure information.

sch ref												
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	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	3,501	2,624	2,655	2,693	2,741	2,799	2,857	2,917	2,979	3,041	2,907
11	System growth	2,961	2,311	2,606	3,611	4,527	3,298	3,493	3,566	3,641	3,717	3,553
12	Asset replacement and renewal	13,047	12,503	11,745	11,749	10,856	17,196	19,021	19,278	19,919	19,531	17,343
13	Asset relocations	409	118	119	121	123	125	128	131	134	136	130
14	Reliability, safety and environment:											
15	Quality of supply	331	471	588	483	607	502	513	523	534	546	521
16	Legislative and regulatory			-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	3,597	4,174	3,669	3,321	3,149	1,477	1,651	1,862	2,066	2,109	2,016
18	**Total reliability, safety and environment**	3,928	4,644	4,257	3,804	3,756	1,979	2,163	2,385	2,600	2,655	2,537
19	**Expenditure on network assets**	23,846	22,200	21,383	21,976	22,003	25,397	27,662	28,277	29,272	29,081	26,471
20	Expenditure on non-network assets	100	65	-	-	-	-	-	-	-	-	-
21	**Expenditure on assets**	23,946	22,265	21,383	21,976	22,003	25,397	27,662	28,277	29,272	29,081	26,471
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	2,620	525	531	539	548	560	571	583	596	608	581
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	21,326	21,740	20,852	21,438	21,455	24,837	27,091	27,693	28,676	28,472	25,890
28												
29	Assets commissioned	19,610	21,433	20,314	20,878	20,903	24,127	26,279	26,863	27,808	27,626	25,148
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	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
32		**$000 (in constant prices)**										
33	Consumer connection	3,501	2,624	2,624	2,624	2,624	2,624	2,624	2,624	2,624	2,624	2,456
34	System growth	2,961	2,311	2,575	3,519	4,334	3,092	3,207	3,207	3,207	3,207	3,002
35	Asset replacement and renewal	13,047	12,503	11,606	11,449	10,392	16,122	17,467	17,339	17,547	16,851	14,656
36	Asset relocations	409	118	118	118	118	118	118	118	118	118	110
37	Reliability, safety and environment:											
38	Quality of supply	331	471	581	471	581	471	471	471	471	471	441
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	3,597	4,174	3,625	3,236	3,014	1,385	1,516	1,674	1,820	1,820	1,704
41	**Total reliability, safety and environment**	3,928	4,644	4,206	3,707	3,595	1,856	1,987	2,145	2,290	2,290	2,144
42	**Expenditure on network assets**	23,846	22,200	21,129	21,416	21,063	23,811	25,402	25,432	25,786	25,090	22,369
43	Expenditure on non-network assets	100	65	-	-	-	-	-	-	-	-	-
44	**Expenditure on assets**	23,946	22,265	21,129	21,416	21,063	23,811	25,402	25,432	25,786	25,090	22,369
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Overhead to underground conversion	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
49	Research and development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	-	31	69	117	175	233	293	355	417	450
System growth	-	-	31	92	193	206	285	359	434	510	551
Asset replacement and renewal	-	-	139	300	464	1,073	1,554	1,939	2,372	2,680	2,687
Asset relocations	-	-	1	3	5	8	10	13	16	19	20
Reliability, safety and environment:											
Quality of supply	-	-	7	12	26	31	42	53	64	75	81
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	44	85	135	92	135	187	246	289	312
Total reliability, safety and environment	-	-	50	97	160	124	177	240	310	364	393
Expenditure on network assets	-	-	254	560	940	1,585	2,260	2,844	3,486	3,990	4,102
Expenditure on non-network assets	-	-	-	-	-	-	-	-	-	-	-
Expenditure on assets	-	-	254	560	940	1,585	2,260	2,844	3,486	3,990	4,102

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11a(ii): Consumer Connection						
*Consumer types defined by EDB**	$000 (in constant prices)					
Customer Connections (≤ 20kVA)	1,043	1,069	1,069	1,069	1,069	1,069
Customer Connections (21 to 99kVA)	475	522	522	522	522	522
Customer Connections (≥ 100kVA)	521	644	644	644	644	644
Distributed Generation Connection	6	6	6	6	6	6
New Subdivisions	866	383	383	383	383	383
Open Country Dairy 33kV & Substation	359					
Open Country Dairy 11kV	46					
Blue Sky Meats Upgrade	-					
Mataura Valley Milk	185					
**include additional rows if needed*						
Consumer connection expenditure	3,501	2,624	2,624	2,624	2,624	2,624
less Capital contributions funding consumer connection	2,620	1,574	1,574	1,574	1,574	1,574
Consumer connection less capital contributions	881	1,050	1,050	1,050	1,050	1,050
11a(iii): System Growth						
Subtransmission	806	-	-	-	-	604
Zone substations	1,417	1,389	467	2,012	2,040	1,551
Distribution and LV lines	207	258	561	407	608	484
Distribution and LV cables	141	182	424	301	462	-
Distribution substations and transformers	233	300	699	497	762	302
Distribution switchgear	141	182	424	301	462	151
Other network assets	15		-	-		-
System growth expenditure	2,961	2,311	2,575	3,519	4,334	3,092
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	2,961	2,311	2,575	3,519	4,334	3,092

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11a(iv): Asset Replacement and Renewal		$000 (in constant prices)					
Subtransmission		468	1,157	561	406	406	406
Zone substations		1,229	1,514	1,414	1,414	1,182	4,087
Distribution and LV lines		5,544	4,263	4,263	4,263	4,263	4,765
Distribution and LV cables		25	710	688	688	688	1,355
Distribution substations and transformers		1,622	1,587	1,516	1,516	1,516	1,685
Distribution switchgear		3,838	3,190	3,082	3,080	2,256	3,743
Other network assets		322	82	82	82	82	82
Asset replacement and renewal expenditure		13,047	12,503	11,606	11,449	10,392	16,122
less Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
Asset replacement and renewal less capital contributions		13,047	12,503	11,606	11,449	10,392	16,122

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11a(v): Asset Relocations							
*Project or programme**		$000 (in constant prices)					
Line Relocations		115	118	118	118	118	118
Fairlight Regulator Relocation		294				-	-
**include additional rows if needed*							
All other project or programmes - asset relocations							
Asset relocations expenditure		409	118	118	118	118	118
less Capital contributions funding asset relocations				-	-	-	-
Asset relocations less capital contributions		409	118	118	118	118	118

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11a(vi): Quality of Supply							
*Project or programme**		$000 (in constant prices)					
Supply Quality Upgrades		104	350	350	350	350	350
Mobile Substation Site Made Ready		227	-	231	-	231	-
Network Improvement Projects		-	121	-	121	-	121
**include additional rows if needed*							
All other projects or programmes - quality of supply							
Quality of supply expenditure		331	471	581	471	581	471
less Capital contributions funding quality of supply		-	-	-	-	-	-
Quality of supply less capital contributions		331	471	581	471	581	471

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		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(vii): Legislative and Regulatory

Project or programme*	$000 (in constant prices)					
*include additional rows if needed						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(viii): Other Reliability, Safety and Environment

Project or programme*	$000 (in constant prices)					
Earth Upgrades	1,757	2,947	2,926	2,926	2,839	1,210
Substation Safety	434	244	244	-	-	-
Replace Xiria Switchgear Gorge Road	605	-	-	-	-	-
Remote Area Power Supply	-	133	133	133	-	-
Hillside Protection Remediation	99	369	-	-	-	-
NMK Blast Wall	165	-	-	-	-	-
NER Installations	86					
Communications Projects	450	480	322	177	175	175
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	3,597	4,174	3,625	3,236	3,014	1,385
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	3,597	4,174	3,625	3,236	3,014	1,385

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	$000 (in constant prices)					
*include additional rows if needed						
All other projects or programmes - routine expenditure						
Routine expenditure	-	-	-	-	-	-

Atypical expenditure

Project or programme*						
Racecourse Road - Parking upgrade	30					
Lumsden Depot	70					
Racecourse Road - Porch upgrade		50				
Racecourse Road - Reception upgrade		15				
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	100	65	-	-	-	-
Expenditure on non-network assets	100	65	-	-	-	-

AMP Planning Period **1 April 2021 – 31 March 2031**

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).
This information is not part of audited disclosure information.

sch ref

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	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	3,785	3,374	3,415	3,463	3,525	3,767	3,847	3,927	4,010	4,094	4,180
11	Vegetation management	1,611	1,215	1,230	1,247	1,269	1,296	1,323	1,351	1,379	1,408	1,438
12	Routine and corrective maintenance and inspection	4,294	4,910	4,975	4,653	4,739	5,074	5,183	5,294	5,408	5,525	5,644
13	Asset replacement and renewal	794	880	870	882	898	874	873	891	910	929	948
14	**Network Opex**	10,484	10,380	10,489	10,245	10,432	11,011	11,226	11,463	11,707	11,956	12,210
15	System operations and network support	1,679	1,954	1,575	1,604	1,629	1,629	1,629	1,629	1,629	1,629	1,629
16	Business support	3,119	2,746	3,154	3,211	3,261	3,261	3,261	3,261	3,261	3,261	3,261
17	**Non-network opex**	4,799	4,700	4,730	4,815	4,889	4,889	4,889	4,889	4,889	4,889	4,889
18	**Operational expenditure**	15,282	15,080	15,219	15,059	15,321	15,901	16,115	16,353	16,596	16,845	17,099

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	3,785	3,374	3,374	3,374	3,374	3,532	3,532	3,532	3,532	3,532	3,532
23	Vegetation management	1,611	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215	1,215
24	Routine and corrective maintenance and inspection	4,294	4,910	4,916	4,534	4,537	4,757	4,760	4,761	4,764	4,766	4,769
25	Asset replacement and renewal	794	880	860	860	860	820	802	802	802	802	802
26	**Network Opex**	10,484	10,380	10,365	9,983	9,986	10,324	10,308	10,310	10,313	10,315	10,318
27	System operations and network support	1,679	1,954	1,575	1,604	1,629	1,629	1,629	1,629	1,629	1,629	1,629
28	Business support	3,119	2,746	3,154	3,211	3,261	3,261	3,261	3,261	3,261	3,261	3,261
29	**Non-network opex**	4,799	4,700	4,730	4,815	4,889	4,889	4,889	4,889	4,889	4,889	4,889
30	**Operational expenditure**	15,282	15,080	15,094	14,798	14,875	15,213	15,198	15,200	15,202	15,205	15,207
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	297	324	329	334	339	344	349	354	359	364	369

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

38

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	40	88	151	235	314	395	478	562	648
43	Vegetation management	-	-	15	32	54	81	108	136	164	193	223
44	Routine and corrective maintenance and inspection	-	-	59	119	203	317	423	533	644	758	875
45	Asset replacement and renewal	-	-	10	22	38	55	71	90	108	127	147
46	**Network Opex**	-	-	124	261	446	687	917	1,153	1,394	1,640	1,892
47	System operations and network support	-	-	-	-	-	-	-	-	-	-	-
48	Business support	-	-	-	-	-	-	-	-	-	-	-
49	**Non-network opex**	-	-	-	-	-	-	-	-	-	-	-
50	**Operational expenditure**	-	-	124	261	446	687	917	1,153	1,394	1,640	1,892

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2021 – 31 March 2031**

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)							
	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**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.1%	0.4%	1.1%	93.4%	5.0%	-	3	1%
11	All	Overhead Line	Wood poles	No.	12.3%	12.5%	3.7%	70.9%	0.5%	-	3	7%
12	All	Overhead Line	Other pole types	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.0%	20.0%	53.0%	3.0%	19%	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	78.4%	21.6%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	100.0%	-	-	3	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	5.0%	85.0%	5.0%	5.0%	-	3	1%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.0%	-	-	3	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	5.0%	15.0%	80.0%	2.5%	-	4	33%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	2.0%	20.0%	75.0%	3.0%	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	2.0%	10.0%	78.0%	10.0%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	7.0%	10.0%	75.0%	8.0%	-	4	9%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	2.0%	15.0%	81.0%	2.0%	-	4	8%

36					Asset condition at start of planning period (percentage of units by grade)							
37	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
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1.0%	6.0%	10.0%	77.0%	6.0%	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.0%	4.0%	25.0%	45.0%	5.0%	20%	3	4%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	1.0%	4.0%	30.0%	40.0%	5.0%	20%	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	5.0%	70.0%	5.0%	20%	3	0%
44	HV	Distribution Cable	Distribution UG PILC	km	-	2.0%	8.0%	65.0%	5.0%	20%	3	4%
45	HV	Distribution Cable	Distribution Submarine Cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	1.0%	7.0%	77.6%	14.4%	-	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	13.3%	20.0%	60.0%	7%	3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.0%	6.0%	15.0%	47.9%	5.1%	25%	3	3%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	3.0%	10.0%	81.1%	5.9%	-	4	9%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	1.2%	14.0%	60.0%	4.8%	20%	3	3%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	1.0%	8.7%	85.0%	5.3%	-	3	5%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	81.0%	19.0%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
55	LV	LV Line	LV OH Conductor	km	1.0%	4.0%	28.5%	40.0%	6.5%	20%	3	1%
56	LV	LV Cable	LV UG Cable	km	1.0%	4.0%	10.0%	60.0%	5.0%	20%	3	1%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.0%	4.0%	19.0%	50.0%	6.0%	20%	3	0%
58	LV	Connections	OH/UG consumer service connections	No.	1.0%	4.0%	14.1%	55.0%	5.9%	20%	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	26.0%	10.0%	17.0%	16.0%	31.0%	-	3	2%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	5.0%	3.0%	85.0%	7.0%	-	4	1%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.0%	-	-	4	-
62	All	Load Control	Centralised plant	Lot	-	26.0%	26.0%	48.0%	-	-	4	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2021 – 31 March 2031**

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**

8

	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	Athol	1	-	N	2	-	-	-	No constraint within +5 years	
10	Awarua Chip Mill	2	-	N	1	-	-	-	No constraint within +5 years	
11	Bluff	6	13	N-1	2	43%	13	46%	No constraint within +5 years	
12	Centre Bush	4	-	N	1	-	-	-	No constraint within +5 years	
13	Colyer Road	10	12	N-1	4	81%	12	87%	No constraint within +5 years	
14	Conical Hill	4	5	N-1	1	70%	5	74%	No constraint within +5 years	
15	Dipton	1	-	N	0	-	-	-	No constraint within +5 years	
16	Edendale Fonterra	29	46	N-1	-	63%	46	65%	No constraint within +5 years	
17	Edendale	7	12	N-1	2	56%	12	58%	No constraint within +5 years	
18	Glenham	2	-	N	1	-	-	-	No constraint within +5 years	
19	Gorge Road	4	-	N	2	-	-	-	No constraint within +5 years	
	Hedgehope	2	-	N	2	-	-	-	No constraint within +5 years	
	Hillside	1	-	N	1	-	-	-	No constraint within +5 years	
	Isla Bank	2	-	N	2	-	-	-	No constraint within +5 years	
	Kelso	4	-	N	2	-	-	-	No constraint within +5 years	
	Kennington	7	12	N-1 switched	4	61%	12	82%	No constraint within +5 years	
	Lumsden	4	-	N	1	-	-	-	No constraint within +5 years	
	Makarewa	4	12	N-1	2	36%	12	37%	No constraint within +5 years	
	Mataura	7	10	N-1	2	70%	10	72%	No constraint within +5 years	
	Monowai	0	-	N	-	-	-	-	No constraint within +5 years	
	Mossburn	2	-	N	2	-	-	-	No constraint within +5 years	
	North Gore	10	10	N-1	8	101%	10	106%	Transformer	Fans can be added to second transformer to increase firm capacity
	North Makarewa	44	45	N-1	-	98%	45	103%	Transformer	Riversdale transferrable between North Makarewa GXP and Gore GXP & continious 2MVA from Monowai Generation
	Ohai	3	-	N	1	-	-	-	No constraint within +5 years	
	Orawia	3	-	N	2	-	-	-	No constraint within +5 years	
	Otatara	4	-	N	3	-	-	-	No constraint within +5 years	
	Otautau	4	-	N	3	-	-	-	No constraint within +5 years	
	Riversdale	6	-	N	2	-	-	-	No constraint within +5 years	
20	Riverton	5	8	N-1	3	72%	8	77%	No constraint within +5 years	
21	Seaward Bush	8	10	N-1	4	78%	10	80%	No constraint within +5 years	
22	South Gore	11	12	N-1	8	90%	12	96%	No constraint within +5 years	
23	Te Anau	7	12	N-1	1	54%	12	57%	No constraint within +5 years	
24	Tokanui	1	-	N	1	-	-	-	No constraint within +5 years	
25	Underwood	11	20	N-1	4	55%	20	55%	No constraint within +5 years	
26	Waikaka	1	-	N	1	-	-	-	No constraint within +5 years	
27	Waikiwi	13	23	N-1	2	55%	23	60%	No constraint within +5 years	
28	Winton	11	12	N-1	3	94%	12	99%	Transformer	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

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.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

		Number of connections					
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended		**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
*Consumer types defined by EDB**							
Customer Connections (≤ 20kVA)		338	287	287	287	287	287
Customer Connections (21 to 99kVA)		28	24	24	24	24	24
Customer Connections (≥ 100kVA)		3	3	3	3	3	3
Connections total		369	314	314	314	314	314

**include additional rows if needed*

Distributed generation

Number of connections		49	42	42	42	42	42
Capacity of distributed generation installed in year (MVA)		0	0	0	0	0	0

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Maximum coincident system demand (MW)	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
GXP demand		153	155	156	157	158	160
plus Distributed generation output at HV and above		9	9	9	9	9	9
Maximum coincident system demand		163	164	165	166	168	169
less Net transfers to (from) other EDBs at HV and above		1	1	2	2	2	2
Demand on system for supply to consumers' connection points		161	162	164	165	166	167
Electricity volumes carried (GWh)							
Electricity supplied from GXPs		621	624	627	630	634	637
less Electricity exports to GXPs		30	30	30	30	30	30
plus Electricity supplied from distributed generation		184	184	184	184	184	184
less Net electricity supplied to (from) other EDBs		13	13	13	13	13	13
Electricity entering system for supply to ICPs		762	765	768	771	774	778
less Total energy delivered to ICPs		720	723	726	729	732	735
Losses		42	42	42	42	43	43
Load factor		54%	54%	54%	53%	53%	53%
Loss ratio		5.5%	5.5%	5.5%	5.5%	5.5%	5.5%

Company Name	**The Power Company Limited**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	131.5	131.5	131.5	131.5	131.5	145.7
12	Class C (unplanned interruptions on the network)	155.0	153.4	151.8	150.3	148.7	146.4
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.61	0.61	0.61	0.61	0.61	0.67
15	Class C (unplanned interruptions on the network)	3.46	3.42	3.39	3.35	3.31	3.28

Company Name The Power Company Limited

For Year Ended 31 March 2021

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Inflationary assumptions were used to calculate the nominal prices in the forecast.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Nominal Prices are based on NZ Treasury's economic forecasts, as published in the Half Year Economic and Fiscal Update released Dec 2019.

	2020/21	2021/22	2022/23	2023/24	2024/25
Inflator OPEX	1.4%	1.2%	1.4%	1.8%	2.1%

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan

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.

Q No.	Function	Question	Score Mar 2019	Maturity Level Description
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2.2	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.
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?	2.2	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.
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?	2.4	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.
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?	1.8	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.
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?	2.3	Communicated to those responsible for delivery is either irregular or ad-hoc.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	1.8	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.
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)	2.4	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.
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?	2.7	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.

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)?	1.9	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.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2.0	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.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	1.8	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.
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?	1.8	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
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)?	1.8	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.
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?	1.7	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.
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?	2.2	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.
53	Communication, participation, 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?	2.1	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.
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?	2.3	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.
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?	2.2	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.
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?	1.8	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.

64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2.3	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.
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	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.
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?	2.4	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.
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?	2.2	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.
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?	2.2	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.
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?	2.4	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	1.8	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.
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?	2.3	The organisation understands the requirements and is in the process of determining how to define them.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1.8	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.
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?	2.4	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.

113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2.7	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.
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?	1.9	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.

THEPOWERCOMPANYLTD

Appendix 4 - Directors Approval

Certification for Year-beginning Disclosures

We, Douglas William Fraser and, Donald Owen Nicolson being Directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of The Power Company Limited prepared for the purposes of clause 2.6.1 and 2.6.6 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 forecasts in Schedules 11a, 11b, 12a, 12b, 12c, 12d and 14a are based on objective and reasonable assumptions which both align with The Power Company Limited's corporate vision and strategy and are documented in retained records.

D W Fraser

D O Nicolson

Date: 24/03/2020