networktasman

Your consumer-owned electricity distributor

PRICING METHODOLOGY DISCLOSURE

Effective 1 April 2025

Pursuant to Electricity Distribution Information Disclosure Determination (Issued 1 October 2012). For compliance with Part 2.4: Disclosure of Pricing and Related Information.

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Your consumer owned eletricity distributor

Contents

Director Certificate

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Directors Certificate

Commerce Act (Electricity Distribution Service Information Disclosure) Determination 2012 Schedule 17

Clause 2.9.1

Schedule 17: Certification for Pricing Methodology Disclosure

We, Sarah Louise Smith and Anthony Page Reilly, being directors of Network Tasman Limited, certify that, having made all reasonable enquiry to the best of our knowledge:

a) the following attached information of Network Tasman Limited prepared for the purposes of clause 2.4.1 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.

SLSmith
.... Date: 26 February 2025

APReilly
.... Date: 26 February 2025

Executive summary

This Pricing Methodology Disclosure for the 2025/26 pricing year, effective from 1 April 2025, outlines Network Tasman's approach to setting electricity distribution prices in compliance with the Electricity Distribution Information Disclosure Determination 2012. This methodology ensures prices remain transparent, economically efficient, and subsidy-free, balancing cost recovery, consumer affordability, and regulatory obligations.

A key update for 2025 is the transition to allocating indirect network costs to Group 3 on the basis of fused capacity-based. Indirect network costs have been allocated to the other mass market consumer groups based on fused capacity for some time. Allocations to Group 3 were based on transformer capacity as fused capacity was unavailable. With the introduction of a Group 3 capacity charge in 2024, Network Tasman now has accurate fused capacity data. Aligning Group 3 with other mass-market groups improves the consistency and fairness of our cost allocations.

To maintain economic efficiency and fairness, Network Tasman has undertaken a subsidy-free cost analysis, calculating price ranges that fall between avoidable costs (the minimum cost of supplying a consumer group) and standalone costs (the cost of bypassing the network altogether). This ensures that each consumer group contributes fairly to network costs while avoiding cross-subsidisation. The results confirm that Network Tasman's pricing sits within the subsidy-free range, supporting cost-reflective and sustainable pricing.

Network Tasman's total revenue requirement for 2025/26 is set at $48.1 million, an increase from $43.2 million in the previous year. This increase reflects rising capital and operational costs, driven by inflation and network investments.

Consumers are categorised into distinct load groups (0 to 6) based on their capacity requirements. Each group has a tailored pricing structure designed to recover costs equitably while encouraging efficient electricity use.

A significant pricing reform in recent years has been the transition of mass-market consumers (Groups 1 and 2) to time-varying tariffs. Since April 2023, Network Tasman has assigned all consumers with communicating advanced meters (AMI) to mandatory time-of-use (TOU) pricing to encourage demand flexibility. The Peak/Off-peak structure provides clearer price signals that incentivise consumers to shift their electricity usage away from peak periods, thereby improving network efficiency and reducing long-term infrastructure costs. Exceptions to this policy are limited, applying only to consumers with non-communicating meters and legacy Day/Night tariffs, which remain in place until future pricing adjustments are feasible.

In line with Electricity Authority recommendations, Network Tasman has also set peak prices with reference to Long-Run Marginal Cost (LRMC). By modelling the expected cost of future network investment, the company has established cost-reflective peak pricing, ensuring that higher charges during peak demand periods reflect the costs of maintaining and expanding the network.

At the same time, Network Tasman has continued its strategy of reducing off-peak and controlled tariffs, reinforcing incentives for consumers to shift consumption to lower-cost periods.

This disclosure provides a clear, structured, and forward-looking pricing methodology, serving as both a compliance document and a strategic framework. It guides Network Tasman's approach to pricing in a way that supports long-term network sustainability and delivers value to consumers.

1. Introduction

1.1. About Network Tasman

Network Tasman Limited owns and operates the electricity distribution network in the Nelson and Tasman regions (excluding Nelson City). The area covered by the network is diverse, ranging from relatively dense urban areas to remote rural areas. The network serves over 43,000 connections and distributes 648 GWh of electricity annually, with a peak load of 132 MW.

The company is 100% consumer-owned through the Network Tasman Trust and aims to provide safe, reliable, and cost-effective electricity distribution services.

1.2. Purpose of this Document

This Pricing Methodology Disclosure outlines how Network Tasman determines its electricity distribution prices for the 2025/26 pricing year. It provides transparency on how pricing structures are set and applied to different consumer load groups and the cost allocation methodology, ensuring fair revenue recovery while minimising price distortions and compliance with the Electricity Distribution Information Disclosure Determination 2012 (sections 2.4.1 to 2.4.5).

Document Structure

- Section 2: Overview of pricing structures for different consumer groups.
- Section 3: Core pricing methodology, including revenue forecasting and cost allocation.
- Section 4: Explanation of how final prices are determined.
- Section 5: Pricing for non-standard contracts.
- Section 6: Pricing considerations for Distributed Generation (DG).
- Section 7: Alignment with Electricity Authority Pricing Principles.
- Section 8: Future pricing strategy and planned improvements.

Network Tasman's prices are charged to electricity retailers, who then determine how to incorporate these charges into the final retail prices consumers see.

2. Our pricing from 1 April 2025

2.1. Consumer load groups and price structures

Network Tasman primarily allocates consumers into load groups according to capacity requirements. Generally, this is measured by the fused capacity of the consumer's connection. Connections are grouped this way because peak demand largely drives network costs. Capacity requirements represent the theoretical maximum load of each connection during the network peak. Although few connections use their full capacity, capacity represents a reasonable proxy for grouping connections with similar peak demands that are likely to impose similar costs on Network Tasman.

Group 0: Unmetered connections

This load group category is for unmetered supplies such as electric fences, phone booths, streetlights and other very low loads. There are two types of Group 0 connections. They are:

- **0UNM (Low capacity supplies)**: For low capacity connections with low consumption that is fitted with a small fuse. It is intended for connections such as phone boxes, roadside communication cabinets and electric fences The price is structured as a fixed charge per day.
- **0STL (Streetlights)**: Used for general street lighting and unmetered streetlights associated with a standard metered connection. The charge is based on the installed streetlight capacity (watts) and is charged on a $/W/day basis.

Group 1: Metered connections up to 15kVA

Group 1 connections have a fused capacity of 15kVA. Most residential consumers and some small businesses are Group 1 connections. Group 1 is comprised of three price categories:

- **1GL (General)**: For non-residential connections such as businesses, shops, sports clubs, etc.
- **1RL (Residential – low use)**: Designed for primary residences that use less than 8,000kWh per year. This price category is regulated by the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (LFC regulations).
- **1RS (Residential – standard use)**: Designed for connections that are either primary residences using more than 8,000kWh per year or residential connections that aren't a primary residence, such as a bach.

Fixed charges for Group 1 consumers are structured as a $/day charge. For price categories 1GL and 1RS, the fixed charge is $1.212/day. The fixed charge for price category 1RL is regulated by the LFC regulations, which caps the fixed charge at $0.75/day.

All three Group 1 price categories have the choice of the variable price category codes described below.

Uncontrolled Prices

Network Tasman has three tariff options for uninterrupted supply. These are:

- Peak/Off-peak;

- Anytime; and
- Day/Night.

The Peak/Off-peak tariff is the default uncontrolled supply tariff for Group 1 connections. All connections with a communicating AMI meter are assigned this tariff by default. The Day/Night tariff was closed for new consumers on 1 April 2023. The Anytime tariff is only available to consumers with analogue or non-communicating AMI meters.

Controlled Prices

Network Tasman also offers controlled supply options that can be added to the base uncontrolled plans outlined above. These are:

- **Controlled water**—This price category code allows Network Tasman to control the consumer's load connected to this circuit, generally a hot water cylinder, within specified service levels.
- **Night only**—Supply under this option is limited to the period between 11 p.m. and 7 a.m. This price category code is typically used for night store heaters, underfloor heating, and night-only water supply.

More than 70% of Group 1 and 24% of Group 2 connections benefit from the controlled hot water price. A further 3% of connections use the night-only option. There are significant benefits for consumers using these tariffs. For consumers on a standard tariff, both options offer prices that are no more than 20% of the standard Anytime tariff.

Group 2: Metered connections 20-150kVA

Group 2 consumers have a fused capacity of between 20kVA and 150kVA.

Fixed charges are recovered from Group 2 connections via a capacity charge. The capacity charge is based on the maximum capacity (kVA) of a consumer's network connection, expressed as $/kVA/day.

Group 2 connections have the same consumption tariff options described for Group 1 consumers above, albeit with different prices to Group 1.

Group 3: Metered connections of 150kVA+

Group 3 consumers have a connection capacity exceeding 150kVA. Revenues are recovered from Group 3 connections via four price components:

- **Fixed daily charge** - The fixed daily charge is set as a $/day charge.
- **Capacity charge** – As with Group 2 connections, the capacity charge is based on each ICP's connection capacity and is structured as a $/kVA/day charge.
- **Anytime maximum demand charge (AMD)** - The AMD charge is measured in kVA based on the single highest half hour of Anytime Maximum Demand (AMD) during the previous 12-month calendar period. The AMD charge is used to recover both distribution and transmission costs. For some connections, the transmission AMD charge has been moderated to manage the bill impact of the move introduced in 2023/24 to away from recovering transmission charges via an RCPD charge.

During this transition, each connection has two AMD charges, one for distribution costs and a second for transmission costs.

- **Seasonal time-of-use** – The seasonal time-of-use charge is a kWh charge which varies according to season (Summer/Winter) and time-of-day (Day/Night).

Group 6: Individually priced customers with capacity > 3MVA

Group 6 consumers have capacity requirements of more than 3MVA and have high levels of asset dedication. Group 6 consumers have fixed charges, which reflect this high level of asset dedication.

2.2. Network Tasman prices from 1 April 2025

Network Tasman reviews its line prices annually, with new prices taking effect from 1 April each year. Our price schedule for 2025/26 is set out in Appendix D.

Charges for new loads connecting to our network can be found in the new load policy on our website. The Electricity Authority has a project proposing to regulate the charges that EDBs can levy on new loads. Should the Authority ultimately decide to regulate the charges, Network Tasman may be required to amend its new load policy to align with the Authority's changes.

The methodology used to set charges for large distributed generation is detailed in Section 6.

Changes by price component

Distribution price component

From 1 April 2025, Network Tasman has forecast an average increase in pre-discount distribution revenue of approximately 11.3% to cover the increasing costs of running our business.

This increase is primarily to account for two factors:

- Inflation and the increasing cost of investing in and operating our distribution network. In particular, the costs of network maintenance and operations, and overheads.
- Increasing capital costs and a large capital program are materially increasing costs.

Pass-through price component

The portion of revenues associated with pass-through costs has increased by $130,000. These costs include industry levies (Electricity Authority, Commerce Commission and Utilities Disputes) and rates. Pass-through costs account for a small percentage (≈1%) of overall lines charges.

Transmission price component

The transmission price component covers the costs that Network Tasman incurs for using the national transmission grid, which is owned and operated by Transpower. Network Tasman has projected that transmission costs will increase by 3.6% for the 2025/26 year.

Two main factors influence this outcome. Network Tasman's transmission charges consist of two parts:

- Regulated transmission charges: These are set according to the regulated transmission pricing methodology.

- Transpower Works Agreement (TWA): TWAs apply when Transpower is requested to build and commission new grid-connected assets for a customer project, such as a new connection or an upgrade of an existing connection to the grid.

The cost of Network Tasman's regulated transmission charges has increased by $1.86 million (17%). This reflects the increase in Transpower's regulated revenues as part of its RCP4 price-quality reset. Network Tasman had two TWAs with Transpower: one for installing a second transformer at the Stoke (66kV) GXP and one for upgrading the capacity of the Kikiwa (11kV) GXP. Both TWAs expire on 31 March 2025. The budgeted annual cost of these two TWAs was $1.41 million.

As a result, there is a net increase of $450,000 (3.6%) in Network Tasman's transmission charges.

Price level changes for individual load groups

The following discussion summarises the average effect of Network Tasman's price changes (pre-discount) on connections in each load group.

Groups 0, 1 and 2

From 1 April 2025, groups 0, 1, 2 are forecast to experience the following changes:

- **Group 0** - overall prices for Group 0 increase on average by 4.1%
- **Group 1** - on average, prices for Group 1 increase by 9%.
- **Group 2** - prices for Group 2 are expected to increase by 4.8% on average.

Group 3

Group 3 connections are forecast to experience an average price increase of 9%.

Group 6

Group 6 connections will experience an average price increase of 11%.

2.3. Consumer Impact

Before implementing a price change, Network Tasman assesses its impact on the affected consumer groups. The effect of price changes on consumers is a key consideration when setting target revenue and prices for these groups.

This analysis assumes that the hypothetical consumer will use the same volume of electricity in 2025/26 as in 2024/25. In reality, consumption varies year-to-year, so the actual effect on individual consumers will also be influenced by this variation and how electricity retailers choose to pass distribution costs to their customers.

Group 1

For standard residential connections, the largest proportional increases will be for those using the least electricity. This is primarily because of the 15c/day increase in the fixed charge, which affects the low fixed charge tariff (LFC tariff). This equates to an increase in lines charges of $1.05/week. For a consumer that uses no electricity throughout the year, this represents a 25% increase in their lines charges. Most consumers, however, use between 4,000kWh and 10,000kWh a year. For these consumers, the daily fixed charge is a much smaller proportion of their overall lines charges. For almost 90% of our consumers, the increase will be no more than $1.50/week. Table 1 below summarises the impact of Network Tasman's pre-discount price changes on residential consumer lines charges.

Table 1 – Annual effect of Network Tasman pre-discount price changes on Group 1 residential consumers

Total kWh/pa	Change in total lines charges ($)	Change in total lines charges (%)
0	$55	25.0%
1,000	$55	19.4%
2,000	$56	15.9%
3,000	$57	13.5%
4,000	$57	11.8%
5,000	$58	10.5%
6,000	$59	9.5%
7,000	$59	8.7%
8,000	$60	8.0%
9,000	$64	8.0%
10,000	$67	8.0%
11,000	$70	8.0%
12,000	$74	8.0%
13,000	$77	8.0%

Group 2

Charges for Group 2 vary by the capacity and consumption of each connection. Group 2 covers a wide array of capacity bands (20kVA to 150kVA), leading to numerous capacity/consumption combinations. The bill impact assessment below is for consumers with a 40kVA connection, a common capacity for Group 2 connections.

Consumers with relatively low consumption will experience the largest increase in line charges for 2025/26 due to the fixed charges increasing slightly more (proportionally) than variable charges. As a result, those who use less electricity see their lines charges increase the most, while those who use more electricity see smaller increases.

Table 2 – Annual effect of Network Tasman pre-discount price changes on Group 2 consumers (40kVA)

Total kWh/pa	Change in total lines charge ($)	Change in total lines charge (%)
0	$102	5.9%
5,000	$112	5.6%
10,000	$121	5.3%
15,000	$131	5.1%
20,000	$140	5.0%
25,000	$150	4.8%
30,000	$159	4.7%
35,000	$169	4.6%
40,000	$178	4.6%
45,000	$188	4.5%
50,000	$197	4.4%
55,000	$207	4.4%
60,000	$216	4.3%
65,000	$226	4.3%
70,000	$235	4.2%
75,000	$244	4.2%
80,000	$254	4.2%

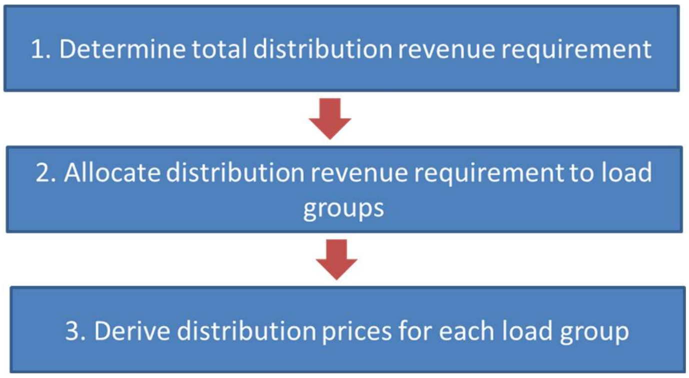
Group 3

Lines charges for Group 3 consumers are set using various ICP-specific metrics, including kWh consumption, connection capacity, and peak demand.

Like Group 2, the characteristics of Group 3 consumers are varied, making it difficult to comment on bill impact in specific terms. However, on average, Group 3 consumers are expected to see an average price increase of 9%.

3. Core Methodology

The core methodology Network Tasman uses for setting prices for distribution services involves three stages:



Price setting is an iterative process that considers factors such as target revenue, bill impacts, and regulatory obligations, creating a potential feedback loop between the steps. This section focuses on the first two steps illustrated above.

Network Tasman operates under the Commerce Commission's Default Price-Quality Path, which imposes a revenue cap limiting the amount of revenue that can be recovered through prices each financial year. At the time of writing, Network Tasman's forecasted allowable regulated revenue for the 2025/26 year is $57 million.

Network Tasman's focus is to be a successful business that operates a safe and reliable network at the lowest cost to consumers. Despite the revenue cap regulation, the business has not needed to recover the full value of the revenue cap to achieve these goals. Therefore, the target revenue is based on the business's current and future operational needs rather than the allowable revenue set by the Commerce Commission's Price-Quality regulation.

Network Tasman's total post-discount revenue requirement for 2025/26 is $48.1 million, compared to $43.2 million for 2024/25.

3.1. Network Tasman's Costs

Key components of Network Tasman's costs are outlined below, along with the estimates used for these cost components when setting prices:

Table 3: Network Tasman's cost components, 2024/25

Cost component	Cost (m)
Indirect Opex	$4.9
Direct Opex	$13.3
Depreciation	$7.8
Return on Capital	$8.4
Transmission	$13.0
Pass-through	$0.7
Total Revenue Requirement	**$48.1**

The information used to determine the value of these cost components is drawn from various sources, including internal estimates, Network Tasman's line business budget, and financial forecasts.

3.2. Allocation by load group

A large portion of the costs associated with the electrical distribution network are shared across many consumers. Network Tasman uses a number of allocators to apportion costs across consumer groups. These allocators are chosen to reflect the underlying drivers of each cost component, the objective being to allocate costs to the groups that are most responsible for generating them. The application and choice of cost allocators inevitably involve judgment and discretion and can evolve over time. The discussion below outlines the principles used to allocate specific costs.

Cost allocation allows Network Tasman to estimate the cost of supplying each consumer group, which informs decisions about the target revenue required from each consumer group.

We consolidate our costs into the following groups:

- Direct network costs and depreciation
- Indirect network costs
- Transmission charges
- Pass-through costs
- Return of capital

The sections below provide a high-level description of how these costs are allocated across our consumer groups. Appendix G provides more details of the cost allocation methodology, including the specific allocators used.

The pricing for non-standard consumers is calculated in accordance with their contracts and is derived separately from the other consumer groups. Costs are allocated to these consumers in a way that seeks to reflect how their prices are set. The methodologies for allocating costs to Group 6 and Cobb have been identified as areas for improvement. We are developing plans to review and refine these methodologies. This review will be completed as resources allow.

The methodology for allocating costs to new and recently connected large distributed generators is specified in Section 6.

Direct network costs and depreciation

Direct network costs incorporate the costs of network operations and maintenance, overheads related to network activities and depreciation of network assets.

Direct network costs are assigned to the following network asset categories:

- General 400V lines;
- Distribution transformers;
- General 11 kV lines;
- Dedicated 11 kV lines;
- Zone substations;
- Sub-transmission lines;
- Connection specific costs; and
- Other non-specific costs.

For many costs, it is clear which network asset category the cost falls into. For example, operations and maintenance costs related to overhead 400v conductor is assigned to the *General 400V lines*[1] asset category. Similarly, depreciation on 33kV lines is assigned to the *Sub-transmission lines* asset category.

However, other costs are shared across multiple asset categories. For example, vegetation costs are incurred across all network voltage levels. In this case, costs are allocated in proportion to the relative overhead line length of each voltage level.

Appendix G provides more detail on the methodology used for allocating each category of these costs to the asset categories listed above.

The following table maps the network asset categories and the load groups that use those assets.

Table 4: Network segments used by load group

Consumer Group	Network Segment Used
Groups 0 & 1	General 230V/400V/11kV/33kV/66kV
Group 2	General 230V/400V/11kV/33kV/66kV
Group 3	Limited 400V and 11kV/33kV/66kV
Group 6	Dedicated & Semi dedicated network, 33kV & limited 11kV
Group CB	66kV lines
Group MAT	Substation switchgear

Costs related to distribution transformers are allocated to consumer groups based on estimates of each group's total transformer capacity.

[1] For these classifications references to 'lines' refers to lines and cables.

Costs related to all other network asset categories are allocated in proportion to estimates of each load group's 3-year average contribution to network coincident maximum demand (CMD). CMD is used because many network investments and costs are a function of network peak demand.

No lower network costs are attributed to load Group 6, CB or MAT. These groups rely solely on upper network assets for their supply. Allocations for the low voltage network cost components are modified to reflect Group 3's lesser reliance on these assets.

Indirect network costs

Indirect network costs include general administration, overhead costs and depreciation of non-system fixed assets. Management estimates are used to allocate indirect network costs to Group 6, bulk supply and large generator connections.

The remaining indirect network costs are allocated to load Groups 1, 2, and 3 based on their respective shares of fused capacity. While the allocation of indirect costs is less precise than that of direct costs, using an allocator based on installed fuse capacity strikes a balance between allocating costs by customer numbers or demand.

Transmission charges

Network Tasman's transmission charges are comprised of four primary components:

- Connection charge
- Benefits-based charge
- Residual charge

These components are derived according to the regulated Transmission Pricing Methodology (TPM).

<u>Connection costs</u>

Connection costs are levied at each Transpower grid exit point (GXP) for highly dedicated assets used to connect Network Tasman to the grid. Network Tasman allocates connection costs to load groups based on each group's estimated demand contribution coincident with the Anytime Maximum Demand (AMD) for each GXP.

<u>Benefits-based charges</u>

Benefits-based charges and residual charges are allocated to consumer groups using a methodology that replicates, as closely as practicable, how these costs are allocated to Network Tasman under the TPM.

The TPM allocates benefits-based charges to transmission customers using three different methodologies:

- Appendix A – allocates the costs of seven pre-July 2019 interconnection investments
- Simple – allocates the costs of post-2019 low value investments (investments valued at $20m or less)

- Standard - allocates the costs of post-2019 high value investments (>$20m)

We have sought to allocate each of these charges between our consumer groups in a manner that replicates how Transpower allocates each charge to its customers.

Appendix A

Under the TPM, Appendix A benefits-based charges are allocated to transmission customers in proportion to their modelled net private benefits. For load customers, net private benefits are effectively calculated for each trading period during the relevant assessment period by multiplying each transmission customer's load during each trading period by the difference between the actual spot price during each trading period and the estimated equivalent spot prices had the investment in question not been made.

Network Tasman has used each consumer group's relative aggregate load figures (MWh) for the four-year assessment period to allocate Appendix A charges.

Simple Method

For the Simple method, Transpower derives regional net private benefits for each modelled region, then calculates a simple method factor for each member of a regional customer group. Starting allocations are based on the product of a customer's simple method factor and the net private benefit for their region.

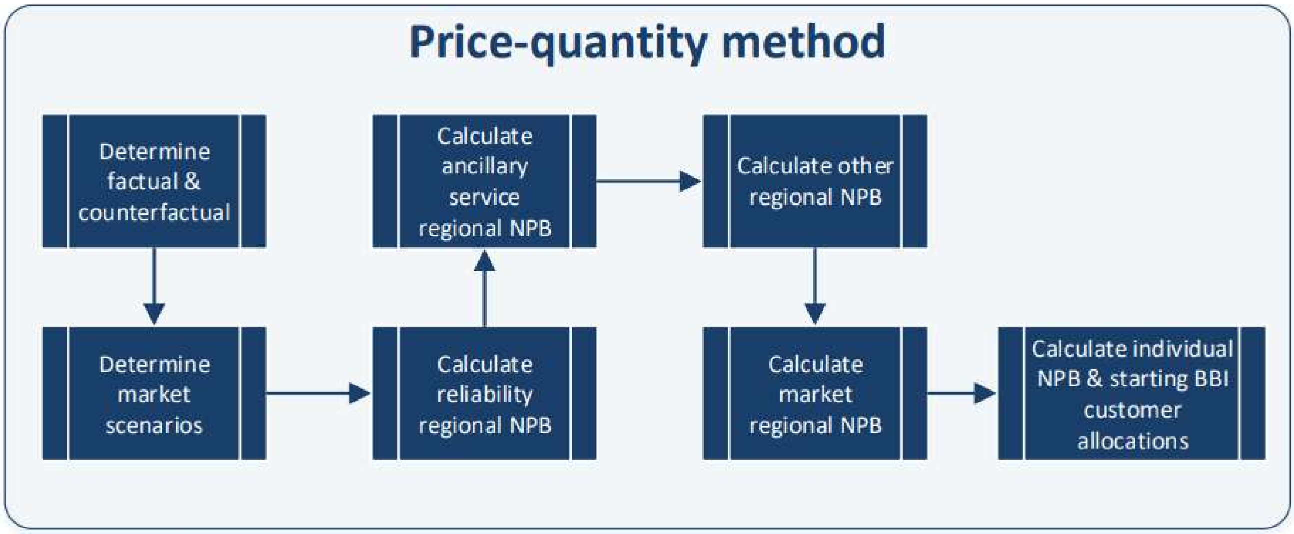
Network Tasman has taken the regional net private benefit as given and allocated simple method benefits-based charges for each investment region to consumer groups based on their contribution to Network Tasman's simple method factor.

Standard Method

The Standard Method is an umbrella term covering several different methodologies. To date, the Price-Quality and Resiliency methods have been used to allocate costs under the Standard Method.

Transpower has used the Standard Method to allocate the costs of three projects. Of these three projects, Network Tasman has been allocated costs for only one of those projects, the Clutha Upper Waitaki Lines Project (CUWLP). Transpower used the Price-Quality method to allocate costs for CUWLP.

Transpower summarises the Price-Quality methodology with the diagram below.



It is neither possible nor proportionate for Network Tasman to replicate most of the steps in this methodology, many of the steps are not published for public scrutiny as they use proprietary software.

In practice, Network Tasman can only replicate the final step of the process, in which Transpower allocates the regional net private benefit (NPB) to customers in that regional group in proportion to their intra-regional allocators.

Intra-regional allocators are derived according to each customer's offtake or injection (kWh) for the relevant assessment period.

Accordingly, Network Tasman allocates its Standard method benefits-based charges to consumer groups in proportion to their relative kWh load during the CUWLP assessment period.

<u>Residual charge</u>

The residual charge is allocated to transmission customers based on their historic maximum gross demand (kW) and lagged average total gross energy (kWh). For kWh data, Network Tasman's database has recorded the equivalent kWh data for each consumer group for the relevant periods. For kW data, Network Tasman's databases only have equivalent internally recorded data for Groups 3, 6 and bulk supply consumers. Network Tasman does not routinely record half hourly demand data for Groups 0, 1 or 2. For Groups 0, 1 and 2, data from the half hourly wholesale market submissions (GR250 report) have been used to calculate the kW demands for each consumer group during the relevant periods.

Consequently, Network Tasman has allocated residual charges to consumer groups using the same parameters that Transpower uses to allocate charges to its customers.

The transitional charge is allocated to consumer groups on the same basis as residual charges.

For large embedded generators, connection costs are allocated using a contractually agreed methodology or according to the incremental costs associated with their connection.

The methodology described above is complex and carries a risk of calculation errors. It is unclear whether this allocation approach results in more efficient outcomes than the less complicated methodologies employed by other EDBs. We consider it likely that our methodology is disproportionately complex and are considering the merits of simplifying our methodology for allocating transmission costs to something more proportionate for future price-setting processes.

Return on Capital

Return on capital is allocated to load groups on a residual basis. As Network Tasman does not price to the Commerce Commission's revenue cap, our revenue requirements are set according to our current and forward-looking operational needs.

Judgement is used when allocating return on capital to load groups, and consideration is given to several factors, including the relative allocations between load groups and the effect of allocation changes on consumers. Where material changes have occurred, the effect of these changes may be introduced over multiple periods to smooth the effect of the change on consumer groups.

Return on capital is derived by dividing net revenues for each consumer group (revenues after subtracting the cost categories outlined above) by the RAB allocated to that same consumer group.

Return on capital is influenced by net revenues recovered from each consumer group and the methodology used to allocate RAB to consumer groups.

RAB is allocated to each consumer group in a similar manner to that used to allocate direct network costs and depreciation to consumer groups.

Pass-through costs

Pass-through costs are made up of industry levies, rates and the FENZ levy.

The Electricity Authority levy is allocated to each consumer group in proportion to their forecast volumes for the pricing year.

For direct billed consumers, all remaining pass-through costs are allocated in proportion to the RAB allocated to the consumer.

The residual unallocated pass-through costs area allocated to mass-market consumer groups (Groups 0 to 3) using network coincident maximum demand.

Revenue requirement by load group

We consider a range of factors when setting revenue requirements for each consumer group, including cost allocations, the effect of price changes on consumers and relativities between load groups.

As a consumer-owned network, the impact of changes to our lines charges on our consumers is a key consideration when setting the revenue requirements outlined in Table 5 below.

Table 5: Revenue requirement by load group ($m)

Consumer Group	Revenue requirement
Group 0	0.2
Group 1	22.3
Group 2	9.8
Group 3	9.4
Group 6	2.0
CB	2.0
MAT	0.0
NEL	1.9
Sundry	0.5
Total	**48.1**

4. Determining prices

This section explains the approach taken by Network Tasman to determine the prices for each load group.

3.3. Setting prices for our consumer groups

Revenue is recovered using a range of price components. These include:

- fixed daily prices (expressed as $/connection/day).
- capacity or demand based prices (e.g. expressed as $/kVA/day).
- consumption prices (expressed as $/kWh).

Consumption prices apply to all consumer groups, except Group 6. Consumption charges vary across price types and can depend on the time of use or the level and type of load interruptability/restrictions the consumer commits to in advance.

In determining the proportions of revenue to be recovered from each price component Network Tasman uses judgment to balance the conflicting demands, including:

- impact on consumers
- economic rationale
- government policy and regulatory requirements
- consumer expectations

The sections below summarise how Network Tasman has structured and set its prices.

Overview

We did not undertake any structural tariff changes for 2025/26, but we have undertaken a number of actions to improve the efficiency of our prices. These actions include:

- Setting peak prices based on a measure of LRMC: We have used an LRMC model to guide the appropriate proportion of revenue to be recovered via fixed and variable charges and inform the efficient level of peak period prices.
- Reduced off-peak and controlled prices: For all consumer groups, the differential between the peak and off-peak tariffs has increased. This has been achieved by increasing the peak prices and reducing the off-peak prices. For standard Group 3 connections the off-peak tariffs are approximately $0.01/kWh. For Groups 1 and 2 the night rates are now close to zero, at $0.0067/kwh and $0.0079c/kWh, respectively. Similarly, prices for the controlled tariffs have also been reduced. The controlled prices for Groups 1 and 2 are both approximately $0.01/kWh.
- Estimated the ‘subsidy-free’ range for each price category: The Authority has stated that it expects EDBs to display their subsidy-free range calculations transparently in their pricing methodologies. The subsidy-free range refers to a window between which revenues recovered from a set of consumers fall between the avoidable costs of supplying those consumers and costs of those

consumers bypassing the distribution network and supplying their electricity needs via alternative sources, generally thought to be via distributed energy resources (distributed generation, storage and demand response), a parallel network connection or a mixture of both. The avoidable cost is the lower bound of the range, and the standalone cost is the upper bound. Details of this calculation are outlined in Section 7.

Groups 1 and 2

Consumers in Groups 1 and 2 have access to the same tariff options, resulting in similar methodology for pricing across both groups.

The Authority's distribution pricing practice note[2] encourages EDBs, in the first instance, to target revenues using cost-reflective prices. Any residual revenues that need to be recovered from consumers should be collected via a 'least distorting' charge.

In its 2024 open letter to distributors,[3]the Authority expanded on what it means by cost-reflective prices when it stated that it expects EDBs to set peak prices based on a measure of long-run marginal cost (LRMC).

Peak prices have been set with reference to LRMC

Network Tasman has used an LRCM model as a reference for level of its peak prices for 2025/26. Using the most recently available disclosed data, we estimate the LRMC of our peak period tariff for LV connections to be $0.092/kWh.

Group 1 contains two categories of tariffs, LFC (1RL) and non-LFC (1RS and 1GL). The requirements of the LFC regulations mean that Network Tasman has two different sets of prices with different price levels. The fixed charge is low for the LFC tariff, while variable charges are higher. Conversely, for non-LFC tariffs, the opposite is true.

This situation poses a challenge in determining which prices to set with reference to the LRMC cost. Network Tasman evaluated three options:

1. Set the peak price of the LFC tariff with reference to the LRMC.
2. Set the peak prices of the non-LFC tariff with reference to the LRMC.
3. Set the weighted average peak price for all Group 1 tariffs with reference to the LRMC.

Since there are broadly similar numbers of ICPs in each group, there is no obvious reason to set one group's prices equal to the LRMC over the other. Consequently, we have set the weighted average peak price for all Group 1 tariffs with reference to the LRMC.

As the LFC phase-out continues, the difference between the standard and LFC prices will narrow and the peak prices of both sets of tariffs will converge on the LRMC.

[2] Electricity Authority, *Distribution Pricing: Practice Note*, Second Edition v2.1, 2022

[3] Electricity Authority, *Open Letter to Distributors*, 20 May 2024

For the 2025/26 pricing year, the weighted average peak price for Group 1 connections has been set with reference to the estimated LRMC at $0.091/kWh. This is an increase of 1.3c/kWh (17%) on the weighted average Group 1 peak price for 2024/25.

Network Tasman has also raised the peak price for Group 2 by 11% to $0.0768/kWh. This is lower than the equivalent peak price for standard Group 1 consumers of $0.0832/kWh. In principle, both prices should be equal because consumers in both groups are connected to the LV network (and subject to the same LRMC estimate). The rate at which the Group 2 peak price is increased has been influenced by a range of factors, including bill shock. Network Tasman intends to continue increasing Group 2 peak prices until it aligns with the LRMC for LV connections, subject to other criteria such as bill shock, price volatility.

Off-peak and controlled prices have been reduced

Network Tasman has also continued to reduce its off-peak and controlled tariffs for all tariffs in Groups 1 and 2.

For many tariffs these prices are very low. The standard Group 1 night price is almost half a cent per kWh ($0.0067/kWh). The controlled tariff has a price of $0.0119/kWh. Standard Group 2 prices for the same tariffs are similar ($0.0079/kWh and $0.0107/kWh, respectively).

The off-peak prices are somewhat higher. Network Tasman introduced the Peak/Off-peak tariff on 1 April 2023 and migrated all Group 1 and 2 ICPs with communicating AMI meters from the default Anytime tariff to the new Peak/Off-peak tariff. To mitigate the bill impact of moving most of our ICPs to a TOU tariff, Network Tasman specified the new tariff so it had a relatively small differential between the peak and off-peak prices. This differential has been increased in each subsequent year, as bill shock allows. Network Tasman intends to continue this trend until the off-peak prices are cost-reflective.

Residual revenues have been recovered via the least distorting charge

Group 1 has three price categories: one for non-residential connections (1GL – General) and two for residential connections (1RL – Residential low use and 1RS – Residential standard use). The fixed charge for price category 1RL is set at 75c/day to comply with the cap on fixed charges imposed by the LFC regulations. The two remaining price categories have a fixed charge of $1.212/day. This price is set to recover the unrecovered residual revenues after setting the cost-reflective variable charges outlined above.

Sixty-six percent of the total revenue collected from Group 1 connections for the 2025/26 pricing year is forecast to be recovered via fixed daily charges. The effect of the LFC regulations pull this figure down. If the 1RL price category is excluded, this figure increases to 73%.

For Group 2, 69% of revenues are recovered via fixed charges.

All transmission charges are recovered via fixed charges only

In response to the Authority's expectation that distributors recover transmission revenues via fixed charges, Network Tasman has rebalanced prices so all transmission costs are recovered from consumers via fixed charges.

All ICP’s have been assigned to time-varying distribution tariffs with limited exceptions

Network Tasman introduced mandatory TOU tariffs for Groups 1 and 2 on 1 April 2023. With limited exceptions, all Group 1 and 2 connections were assigned to these TOU tariffs.

There are two exceptions to this policy:

1. ICPs with legacy (analogue) meters or non-communicating AMI meters may remain on the Anytime tariff. It is not possible (or unreasonably impractical) to routinely report consumption data for these ICPs against the peak and off-peak time periods. Network Tasman considered applying a profile to the consumption figures for these ICPs, or billing them entirely against the peak tariff as we understand other EDBs do. We elected against adopting either of these policies as doing so would have no material effect on the efficiency of the consumer’s network use.
2. ICPs that were on the Day/Night tariff before the Peak/Off-peak tariff was introduced on 1 April 2023 may remain on the tariff. The Day/Night tariff was closed to new ICPs from 1 April 2023, when the Peak/Off-peak tariff was introduced. The reasons for this are twofold:
    a. Many ICPs on the Day/Night tariff have legacy Day/Night meters that cannot record the data required by the Peak/Off-peak tariff.
    b. The peak/Off-peak tariff was introduced with a moderate price differential to manage the risks of bill shock for the consumers that were moved to the tariff on 1 April 2023. The Day/Night tariff has a much larger price differential. Mandatorily moving consumers who had opted into a tariff with a large price differential to a tariff with a much smaller differential would have likely left Day/Night consumers materially worse off whilst also undermining their incentives to shift load into off-peak periods.

Network Tasman will consider options for migrating Day/Night consumers to the Peak/Off-peak tariff when the Peak/Off-peak tariff differential reaches a similar magnitude to the Day/Night tariff.

Group 3

Group 3’s fixed charges were subject to significant reform for the 2024/25 pricing year. In recognition of the level of change this has introduced to Group 3 connections, Network Tasman has not made any reforms to the structure of Group 3 prices for the coming year.

Instead, the focus has been on increasing the peak charges and reducing the off-peak charges for this group.

Group 3 is subject to seasonal time-of-use variable charges, with the winter day tariff being the peak tariff. For the standard Group 3 tariff, the peak price has been increased by 10% for the 2025/26 pricing year. Similarly, the remaining (off-peak) prices have all been reduced by 5%. For the coming pricing year, the peak price is almost seven times higher than the off-peak prices.

The peak prices for Group 3 remain materially below the LRMC value estimated for the Group 3 connections of $0.141/kWh. Bill shock considerations were the primary reason Group 3 peak prices were not increased further. Retailers generally pass Group 3 prices directly through to their customers.

As such, changes to Group 3 prices have a much larger and direct effect on a Group 3 connections electricity costs than equivalent changes do for Group 1 and 2 connections.

Network Tasman is conscious of the effect that rebalancing our peak/off-peak prices too dramatically could have on the commercial operations of a local business.

Network Tasman will continue to adjust these prices as appropriate in the future as we transition to more cost-reflective prices.

Group 6

There are only two consumers in Group 6. Both have sought direct service and billing arrangements with Network Tasman rather than choosing to operate through standard interposed arrangements with electricity retailers.

Group 6 consumers have fully fixed charges and pay an annual fixed rental for their supply, irrespective of their load profiles. These charges were initially set with reference to the assets used to supply these connections and have subsequently been adjusted each year to reflect Network Tasman's broader price adjustments.

This methodology has provided both Network Tasman and Group 6 consumers with revenue/price certainty. However, as a long-standing approach, it would benefit from a review. Preliminary work has begun on revising the methodology for setting Group 6 prices and this work is expected to be completed in time to implement any changes for the 2026/27 pricing year.

Large generators

Three large (1MW+) embedded generators are permanently connected to our network. Prices for one of these generators are set in accordance with the terms of the connection agreement between Network Tasman and the asset owner.

Charges for the remaining two generators have been set using the methodology specified in Section 6.

5. Non-standard contracts

Network Tasman has non-standard contracts with eight consumers (9 ICPs). The target revenue expected to be collected from these consumers is $6m.

Network Tasman does not have a set policy for when a non-standard contract should be used or how prices should be set if a non-standard contract is used.

Non-standard contracts are typically used when a connection requires a high level of asset dedication and/or a service that is, or was, not available under the standard price categories.

Prices for new connections with a non-standard contract are typically set with reference to the assets involved to supply the connection and any attributable charges from Transpower. Many of Network Tasman's non-standard contracts come in the form of legacy connection agreements with larger distributed generators.

Distribution charges for non-standard contracts are usually fixed as they are based on the cost of providing high levels of asset dedication. Transmission and other pass-through costs are generally passed through to the consumer on the same basis as it is charged to Network Tasman, unless otherwise specified in the contract.

In the event of a loss of supply, Network Tasman's obligations and responsibilities to consumers with non-standard contracts are the same as those for consumers with standard contracts.

6. Distributed generation (DG)

Network Tasman uses the regulated terms set out in Schedule 6.2 of Part 6 of the Electricity Industry Participation Code 2010 (Part 6) as a default contract with small scale distributed generation (SSDG) but has more formal connection agreements with five larger hydro plants.

Pricing for four of the hydro plants is specified in the individual connection agreement with each of these distributed generators. The connection agreement with the fifth generator states that prices must be set according to the pricing principles specified in Schedule 6.4 of Part 6. The methodology used to set the prices in accordance with Schedule 6.4 is outlined below.

6.1. General

This section sets out the methodology Network Tasman uses to derive the incremental cost of connecting DG to our network and how it will recover those costs from the DG owner.

The charges outlined below may be recovered up front from the DG owner, calculated on an annual basis, and invoiced in arrears in equal monthly instalments across the pricing year (April-March), or a mixture of both methods.

There are three types of costs that Network Tasman may incur when connecting DG to the network:

- Distribution costs – The cost of deploying new distribution assets to connect the DG to the distribution network, including business support costs incurred by Network Tasman as a result of the connection and operation of the DG in the distribution network;
- Transmission costs – The incremental transmission costs incurred as a result of the connection and operation of the DG on the distribution network;
- Other costs – Other incremental costs incurred by Network Tasman because of DG connecting to our network, including regulatory charges such as Electricity Authority Levies.

If Network Tasman is recovering the incremental costs of connection over the life of the installed assets (or some other agreed timeframe) Network Tasman's policy is to recover the asset-specific costs via a monthly lines charge according to the methodology below. The cost of installing individual assets is included in their value. However, some costs incurred when installing assets cannot be allocated to a specific asset. Where this occurs, these costs may be recovered directly from the DG owner upfront or recovered as a separate item.

Where a DG owner funds all incremental network augmentation costs upfront, Network Tasman applies judgement over whether the ongoing incremental costs associated with the DG connection are sufficiently material to warrant ongoing monthly invoicing.

The costs below will be discussed with DG owners prior to entering into a connection agreement and may be subject to change.

6.2. Distributed generation lines charge

The distributed generation lines charge recovers the costs associated with the line function services provided by Network Tasman in the following situations:

- incremental assets provided for the connection of the DG to the distribution network; and
- use of shared incremental assets that are installed or upgraded to the capacity required by the DG.

The charge comprises three components: a return on investment; depreciation; and maintenance and operation/business support costs.

Return on Investment (ROI)

Network Tasman will value the assets used for conveying electricity produced by DG at the regulatory asset base (RAB) value of the assets or equivalent and apply the Weighted Average Cost of Capital (WACC) applied by the Commerce Commission to set Network Tasman’s revenue cap (7.1% from 1 April 2025).

$$Return\ on\ investment\ = \sum_{asset} Regulated\ WACC \times RAB\ Value_{asset}$$

Where:

Regulated WACC = The WACC estimated by the Commerce Commission for the purposes of default price-quality path regulation.

RAB $value_{asset}$ = The current RAB value or equivalent, in dollars, of each incremental asset used to connect the DG to Network Tasman.

In circumstances where multiple DG share assets that Network Tasman has provided exclusively for conveying electricity produced by DG, the return on investment component will be apportioned according to the ratio of the nameplate capacity of the DG owner's plant to the sum of the total nameplate capacity of all DG owners’ plant using those shared assets. Network Tasman will provide an asset valuation table and apportionment calculations as part of the contract with the DG owner.

Depreciation

Network Tasman will value the assets used exclusively for conveying electricity produced by DG at the value of those assets as recorded in Network Tasman’s RAB or equivalent. An annual depreciation charge will be calculated based on each appropriate asset class's standard physical asset lives. Accordingly, the calculation will be:

$$Depreciation\ charge\ = \sum_{asset} (RAB\ Value_{asset} \times \frac{1}{Remaining\ Life_{asset}})$$

Where:

RAB Value_{asset} = As defined above

Remaining Life_{asset} = The remaining life, in years, of each incremental asset used to connect the DG to Network Tasman. Where applicable, asset lives will be set according to the standard physical asset lives as defined in the Commerce Commission’s Electricity Distribution Services Input Methodologies Determination 2012.

Where multiple DG share assets that Network Tasman has provided exclusively for conveying electricity produced by DG, the depreciation component will be apportioned according to the ratio of the nameplate capacity of the DG owner's plant to the sum of the total nameplate capacity of all DG owners’ plant using those shared assets.

Network Tasman will provide an asset valuation table, table of depreciation charges and, where multiple DG owners are involved, apportionment calculations, as part of its contract with the DG owner.

Maintenance and operations

The cost to Network Tasman of maintaining assets used by DG will vary according to a range of factors, including the:

- specific assets used to connect the DG;
- topography over which the assets are located;
- climate where the assets are located; and
- accessibility of the assets.

Maintenance costs can vary significantly, making it difficult to prescribe a precise methodology for allocating maintenance costs. The methodology for recovering maintenance costs is set on a case-by-case basis. Network Tasman’s default approach is to set maintenance and operations costs at 2% of the value of the incremental assets when they were installed.

Similarly, where the connection of DG imposes incremental administration costs on Network Tasman, these costs will be directly passed on to the DG responsible.

New generation

Where new DG proposes to connect to shared assets that Network Tasman has provided exclusively for conveying electricity produced by other DG owner/s, or an existing DG owner proposes to increase the amount of generation injected into the Network Tasman network, additional assets or network reinforcement may be required to accommodate the new or increased generation and supply the capacity allocated to existing DG. In such circumstances, ROI, depreciation and maintenance charges associated with the additional assets or network reinforcement, as calculated above, shall be attributed to the DG owner requiring the additional investment.

Valuation review

DG connection charges will be adjusted each year to reflect changes in the asset values that underpin the connection charge resulting from asset renewals, revaluations, and replacements.

6.3. Transmission Related Transactions

Network Tasman directly passes on any incremental cost incurred from Transpower due to the connection of new or increased capacity DG to its network. The following describes the most common incremental cost components Network Tasman incurs due to DG connecting to its network.

Recovery of Connection Charges

The incremental cost of any connection assets commissioned because of DG connecting to our network will be passed directly through to the DG owner.

These costs typically arise via a direct increase in connection charges due to installing new assets and an increase in Network Tasman's allocation of existing assets (generally the substation).

Network Investment and Transpower Works Agreements

The cost of any bilateral contract between Transpower and Network Tasman for works or new/upgraded assets that is entered into to accommodate the connection of DG will be passed directly through to the DG owner.

Where applicable, the associated maintenance costs for any new assets installed will be passed directly through to the DG owner as levied by Transpower.

Benefits based charges

Network Tasman does not currently pass on any benefits-based charges to DG. Given the complexity of the calculation of benefits-based charges, the materiality and practicality of determining a DG's contribution to Network Tasman's benefits-based charges will be considered when electing whether to pass these costs on to the connected DG.

6.4. Other Costs

EA Levy

As an industry participant, Network Tasman is required to pay the Electricity Authority's annual levy (EA Levy). Each monthly instalment of the EA Levy is recovered from generators based on:

- the total quantity of electricity conveyed by the distributor during the month; and
- one-twelfth of the total number of ICPs Network Tasman is responsible for at the end of the month.

Where the connection or operation of DG results in the total quantity of electricity conveyed by Network Tasman changing (as assessed by the Electricity Authority), the incremental effect of this change will be passed through to the DG owner.

6.5. Commerce Commission Regulation

As a price/quality regulated distributor, Network Tasman is subject to the Commerce Commission's regulated quality standard. Should Network Tasman breach any of its regulated quality standards and it can be demonstrated that Network Tasman would not have breached the regulated quality standard/s had one or more DG not been connected to our network, Network Tasman will recover the incremental costs incurred from responding to any subsequent breach investigation from the relevant DG owner/s.

6.6. Payments to distributed generation owners

Network Tasman does not currently make ACOT or ACOD payments to distributed generation.

6.7. Price notification

All DG subject to the methodology described above receive a summary of these charges 20 working days prior to the beginning of each pricing year on 1 April.

7. Distribution pricing principles

The Electricity Authority published a decision paper titled "More efficient distribution network pricing – principles and practice" dated 4 June 2019.

The paper published the Authority's new set of Distribution Pricing Principles and its approach to monitoring and promoting progress on distribution pricing reform.

The following identify each Distribution Pricing Principle and discuss the consistency of Network Tasman's pricing with the principle.

Prices are to signal the economic costs of service provision, including by being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs)

The subsidy-free test is a theoretical notion that, at its limit, requires a separate test for each of Network Tasman's ICPs. As a general principle, if line prices are cost-reflective and costs are below bypass levels, the subsidy-free test will be met.

The Authority's 2019 Practice Note offers an alternative basis for the subsidy-free test, emphasizing consumer groups (or connection categories) rather than individual consumers. It defines avoidable costs as the expenses that would decrease if a consumer group were not supplied with electricity. Additionally, it identifies standalone costs as the cost of energy alternatives that could supply groups of consumers, such as micro-grids.

The subsidy-free range for consumer groups is likely to be broad because incremental costs for the additional consumer/kVA/kWh are low while their standalone costs of supply are very high.

In this context we have estimated the boundaries for each connection category as follows.

Avoidable costs

To quantify the operating costs that could be considered avoidable, we use a methodology that draws largely on data disclosed in IDs. We do this because the data is both audited and readily available. We make conservative assumptions about what types of costs could be avoided. That is, we take an approach that is more likely to overstate rather than understate avoidable costs, to reduce the risk of enabling price subsidies.

We assume that sub-transmission assets and zone substations are generally common assets shared by multiple consumer groups and would not generally be avoidable for any consumer group, except for Group 6, where either assets are dedicated or where the customer accounts for a significant proportion of capacity on those assets.

The assets that we assume are avoidable for each of Groups 1, 2 and 3 are distribution and LV assets (lines, cables, distribution substations and transformers, and distribution switchgear). This is a conservative assumption – that is, it would overstate avoidable costs.

We conservatively assume that all categories of network opex are scalable, so that if an asset is abandoned, then network opex will reduce roughly in proportion to the value of the abandoned assets. For non-network opex, we assume that half of "system operations and network support" expenses are scalable and that only 25 per cent of "business support" expenses are scalable. These assumptions allow us to estimate the total amount of opex that is scalable.

We allocate the scalable opex to each asset class according to the RAB value of each asset class. When allocating the opex associated with vegetation, we only allocate it to overhead lines (sub-transmission, LV, and distribution). All other opex types are allocated across all asset types.

To identify the value of assets that could be abandoned, we first allocate the total RAB value across load groups, according to each load groups share of coincident maximum demand (CMD). In doing so, we assume that:

- Groups 1 and 2 use all network assets;
- only some Group 3 customers use distribution LV lines, cables, and switchgear, and they don't use NTL distribution substations and transformers, but all Group 3 customers use all other network asset types; and
- Group 6 customers don't use any asset types relating to distribution or LV network.

We then calculate, for each load group, the value of the assets that we previously identified could be abandoned if the load group was no longer supplied.

Standalone costs

We estimate standalone costs using ID data, both because it is publicly available and audited, but also because grid-connected supply of electricity appears to currently be the lowest cost option. For example, we observe that where new subdivisions or commercial developments are being built, including by new networks such as Lakeland Network in Central Otago, traditional electricity distribution networks are being used rather than alternative options.

To estimate avoidable costs drawing primarily on publicly disclosed information, we first estimate the standalone asset costs and then estimate standalone opex.

To estimate the standalone asset costs for each customer load group, we:

a) Identify which asset classes most resemble common assets, where the value of the assets needed to serve an individual customer load group are similar to value of assets needed to serve all customer load groups. Identify the RAB value of those assets, by asset class for each customer load group.

b) For asset classes that are more attributable to individual load groups (rather than being common to the supply of multiple customer groups), we allocate the RAB value to each customer load group.

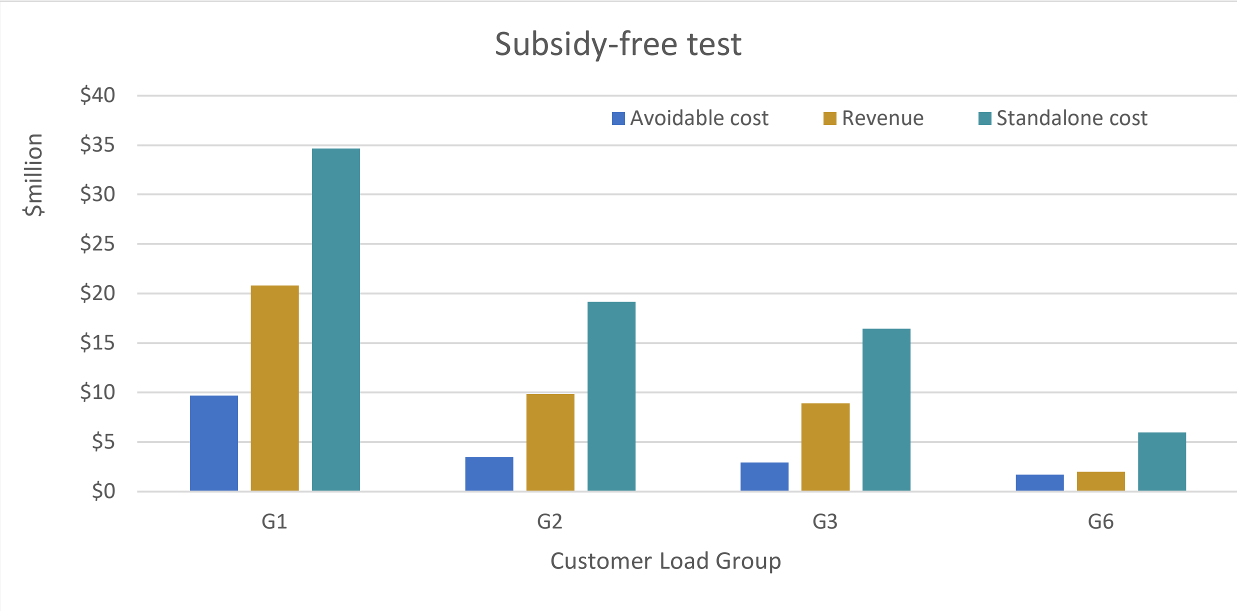
c) For each customer load group, calculate the depreciation and return on capital on common assets and allocated attributable assets to estimate the standalone asset costs.

When considering (a), we assume that for Groups 1, 2 and 3, sub-transmission lines and cables, as well as zone substations, other network assets, and non-network assets are common assets. That is, if the network was only going to serve one of these customer groups, it would still need to invest in these assets in their entirety (or close to it). For example, a sub-transmission network would still be required. In contrast, we assume that assets closer to the customer (LV and distribution asset classes) are more likely to be specific to a customer load group,

For Group 6, we assume that network assets are largely dedicated, so only non-network assets resemble common assets.

For each customer load group, we calculate standalone opex to be avoidable opex (that is, the opex allocated to each attributable asset class), plus the full amount of opex for each common asset class, plus a proportion of non-network opex, where the proportion varies by group.

The results of this modelling are displayed in the figure below.



In all cases, the revenue we receive for each consumer group is greater than the avoidable costs of supplying them and less than standalone costs, demonstrating that our pricing meets the “subsidy free” requirement in principle (a)(i).

Prices are to signal the economic costs of service provision, including by reflecting the impacts of network use of economic costs

Developing price components that reflect the economic costs of use with precision requires, in theory, locational marginal prices, but in practice, the available options are less sophisticated.

Peak demand charges are the most practically available price structure that would be able to accurately signal the costs of network use at time of peak demand.

Metering issues make the widespread use of peak demand charges for lower capacity connections challenging. However, for Group 3 connections with time-of-use meters, Network Tasman has successfully deployed peak demand charges for some time. In the absence of such tariffs at lower capacities, Network Tasman uses capacity charges as a proxy for peak demand charges, setting a theoretical maximum on the peak demand an ICP can place on the network. The small increments in which available fuses increase (5kVA at lower capacities and 10kVA to 20kVA at higher capacities) provide relatively narrow bands for consumers to fall within. These bands ensure that consumers can select a connection capacity that closely aligns with their peak demand whilst also preventing large numbers of ICPs with very different network loads from paying the same charges for their network use.

Group 2 and 3 tariffs feature components directly related to the actual or potential demand these consumers can make on the distribution network and the transmission grid. Group 3 consumers face a capacity charge, derived exclusively from their connection capacity, and an anytime maximum demand charge. These two charges combine to reflect the current and future costs of delivering capacity on the distribution network.

The distribution component of Group 6 network charges is entirely fixed. This fixed charge recognises the highly dedicated supply used by these consumers. Any usage beyond the capacity of the existing dedicated assets would require additional investment and the costs of that investment would be directly passed back to these consumers.

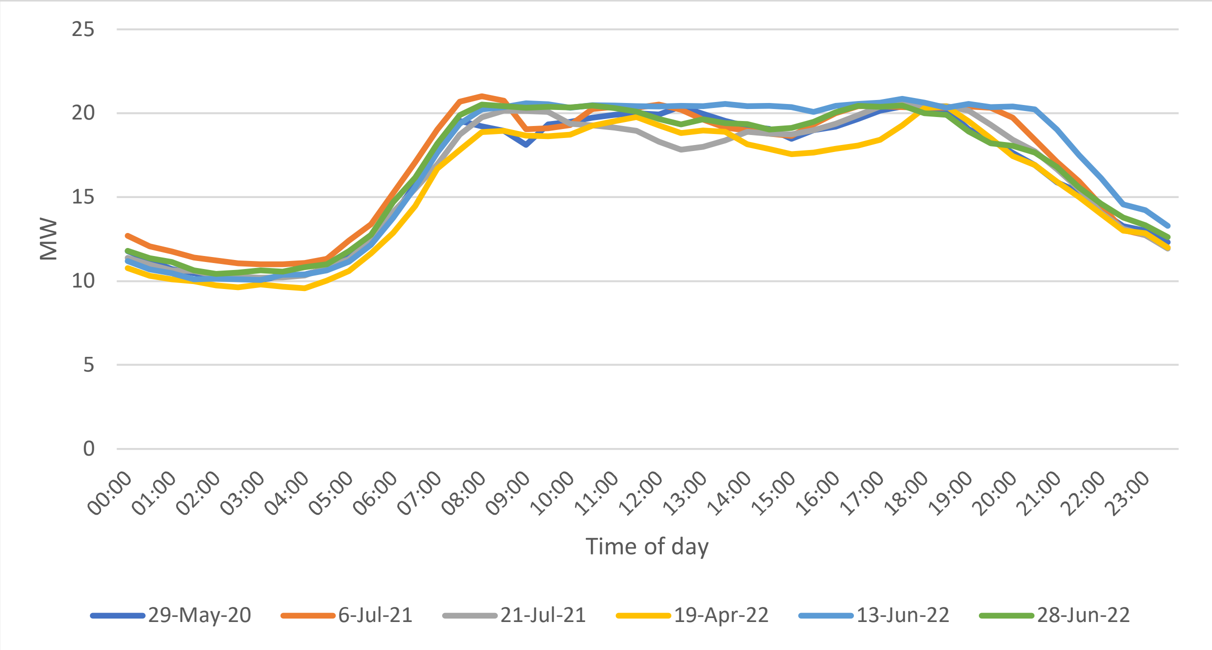
Accordingly, Group 6 customers face the direct costs of congestion, should it occur, be it by curtailing load (and incurring the costs of lower production) or the investment cost of upgrading their dedicated assets.

Where Group 3 consumers use available network and grid capacity inefficiently Network Tasman reserves the right to apply a kVA based power factor correction charge on sites with a non-compliant power factor (PF<0.95).

Applying a mandatory Peak/Off-peak tariff for all Group 1 and 2 consumers with communicating AMI meters also provide these consumers with growing incentives to shift load away from the peak demand periods that trigger network investments. Similarly, the existing seasonal time-of-use tariff for Group 3 consumers provides a similar incentive for those consumers to minimise network use during network peaks.

The structure of the Peak/Off-peak tariff has been carefully calibrated to align with Network Tasman's peak load periods on the coldest days of the year, when we are maximising our ability to control loads on our network.

FIGURE 1: MOTUEKA ZONE SUBSTATION LOAD PROFILE – DAYS OF HIGHEST DEMAND (2020-2022)



The flat load profiles illustrated above are the result of Network Tasman using ripple control to shift load from hot water cylinders away from the traditional morning and evening peak periods, as displayed in Figure 1. These loads are then restored after the underlying peak has passed. This action shaves load off the top of the morning and evening peaks and moves that load to the trough that follows.

As Network Tasman has a reliable and low-cost mechanism to create a flat load profile on the days of highest demand, there is little benefit to be gained from encouraging consumers to use additional scarce resources to shift load away from the peaks into the middle of the day. Instead, the most appropriate tariff structure is a simple peak/off-peak tariff where the peak period applies from morning to evening, and the off-peak period applies overnight. A tariff structured in this way will encourage consumers to shift demand into the late evening (post 11pm) and early morning and maintain (or even improve) Network Tasman's ability to flatten network load and efficiently defer network upgrades.

The level of these peak prices is set using Network Tasman's LRMC model, which improves the efficiency of these peak signals and the resulting network use.

Network Tasman also applies a kVA per kilometre network development levy regime for new loads located on high-cost, uneconomic segments of the network. The levy recognises demands for service capacity in terms of network distance (km) and capacity level (kVA). The network development levy is an up-front charge that recovers incremental costs of network connection directly from those responsible for the cost.

Network Tasman also has a capital contributions policy (new load policy) mechanism that allows flexible loads to share the benefits of deferring/avoiding investment in distribution assets.

Historically, Network Tasman's new load policy allocated network capacity based on the connection's installed fuse capacity. This was in recognition that we do not generally have the ability to limit when a connection uses the network—load is constrained by fuse size only. Similarly, few connections have the ability (or incentives) to manage their load during periods of local network peaks.

Network Tasman's new load policy broadly allocates the cost of network upgrades triggered by a new connection to that connection. With some long rural feeders nearing capacity and facing costly upgrades to serve new capacity, the cost of upgrading these feeders can pose a considerable barrier to new load connecting on them.

Capital contributions calculated based on installed fuse capacity provide little incentive for a flexible load that could avoid the local network peak to connect to the network. Our capital contributions policy includes the option for a *profiled connection*.

A *profiled connection* is available to new connections where network capacity is limited. The new load agrees to a low, or zero, connection capacity during local network peaks while having access to higher-capacity connections during off-peak periods.

This outcome creates a mutually beneficial outcome for the new load and the network. The new load can connect to congested parts of the network without triggering costly network upgrades, and the network improves its ability to host more load on the existing network.

Prices are to signal the economic costs of service provision, including by reflecting differences in network service provided to (or by) consumers.

Network Tasman primarily differentiates its services by connection capacity and firmness of supply.

Network Tasman offers five separate consumer groups, each covering a set connection capacity range. The consumer groups are summarised below:

- Group 0 – Low capacity unmetered connections, such as street lights, phone boxes and roadside communication cabinets.
- Group 1 – Metered connections of capacity up to 15kVA. This price group accounts for most residential consumers and some small businesses.
- Group 2 – Metered connections of capacity between 20kVA to 150kVA. This group tends to consist of most businesses and some large residential households.
- Group 3 – Metered connections of capacity exceeding 150kVA. This group consists of large businesses.
- Group 6 – Individually priced connections with capacity exceeding 3MVA.

These price categories act to differentiate connections based on their capacity and reflect the differences in the service provided.

Group 1 and 2 connections also have the option of a less ‘firm’ electricity supply by opting to have their hot water controlled via ripple control or to limit the use of specific appliances to specific times.

The ability to control hot water charging provides Network Tasman with better tools to manage network load at peak times and defer network investment, as discussed in the section above about developing the Peak/Off-peak tariff.

From the consumer side, having their hot water controlled may affect the supply of hot water, although this is largely mitigated by the service standards that dictate the maximum length of time hot water can be disconnected. Anecdotal evidence indicates that very few consumers are aware their hot water is subject to network control. This suggests the cost to the consumer of a lower "quality" service is small, whereas the benefits are relatively large given the price differential between the controlled tariff option and the uncontrolled tariff options.

Network Tasman also offers a 'night only' tariff, where the use of specific appliances is limited to operating overnight (11pm to 7am). This tariff is typically used for night store heaters, underfloor heating, and night-only water supply.

As noted in the previous section, the introduction of a profiled connection for new loads that can minimise or avoid network use during local network peaks allows them to avoid contributing to costly network upgrades that would be required for equivalent inflexible loads. Where significant network upgrades are required, the economic costs avoided can be significant.

Prices are to signal the economic costs of service provision, including by encouraging efficient network alternatives.

Network Tasman's line prices directly or indirectly encourage the consideration of network alternatives and innovation in the following ways:

- Network Tasman only charges new embedded generators for their incremental network connection costs. Where warranted, Network Tasman will also consider passing through any avoided distribution costs directly attributable to the new embedded generation plant.
- Group 3 prices include a power factor charge for consumer sites with a power factor that is non-compliant (worse than 0.95).
- Group 2 prices include capacity charges based on installed fused sizes. This provides incentives for consumers to minimise their ICP fusing requirements and find ways to avoid increasing peak network demands.
- Network Tasman has default tariff options with higher kWh rates for on-peak consumption than for off-peak or controlled consumption. These differentials have been increased for the 2025/26 pricing year.
- Network Tasman requires an upfront network development levy, reflecting both kVA and distance, for new loads seeking new capacity in uneconomic areas of the network. The development levy signal is stronger the larger the load and the further it is away from Network Tasman GXPs or zone substations. This progressively encourages all remote new loads to minimise their new capacity demands on segments of distribution network that are uneconomic

to reinforce and explore alternative and more efficient ways of supplying their new capacity requirements. It also encourages new loads to locate in lower-cost areas of the network.

- The introduction of the *profiled connection* option offers incentives for new loads to invest in additional load management tools if they are less costly than funding a network upgrade.
- New large loads are subject to an economic test that assesses incremental cost against expected future revenue streams. A capital contribution is sought to cover the difference when there is a shortfall. This incentivises the minimisation of capacity use and consideration of alternatives. It also encourages new loads to be located in lower-cost areas of the network.

New connections/loads on Network Tasman's distribution network are required to fund any new network extension assets (excluding transformers) necessary to connect their new ICP to the existing distribution network. This policy helps Network Tasman avoid funding uneconomic and undesirable network extensions and incentivises new connections to consider the most economic means of getting power to their chosen locations.

Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use

This test of efficient pricing focuses on Ramsey concepts of loading any revenue shortfalls after signalling economic costs onto consumers, products and services that are the least responsive to price changes.

Network Tasman's line charges typically make up 20%-25% of most consumers' power bills while the generation and retail component make up the remaining 70%-75%. As part of the overall price signal consumers are likely to receive, line price signals provide muted consumption signals, if they are passed through to consumers. Sensitivity to choices concerning shortfall recovery is also likely to be muted.

Demand elasticity is largely a function of the availability of substitutes. In terms of electricity delivered through traditional centralised generation plants, power grids, and distribution networks, the alternatives that drive demand elasticity are primarily gas, coal, wood, distributed generation, solar water heating, and energy efficiency substitutes.

For virtually all Network Tasman consumers:

- Coal and gas (other than bottled gas for cooking) are not viable substitutes in this region.
- Incremental use of wood or coal is increasingly being marginalised as a heat source by clean air regulations in Network Tasman's major urban areas, carbon pricing and broader perceptions around social acceptability of these practices.
- Energy efficiency initiatives (insulation, better lighting & appliances, etc.) tend to present one-off opportunities at discrete points of time for consumers to lower part of their consumption for the long term.
- Solar water heating is understood to now be an economic option in many cases when compared to electrically heated water for those installing a new hot water system. Despite this, anecdotal evidence suggests that adoption has been muted. There are several factors contributing to this

outcome, including large upfront capital costs of solar water heating, the practicality of installing equipment on some roof types, incumbency bias, inability of renters to invest in the technology and limited incentives for consumers to unnecessarily replace existing operational hot water systems.

Most electrical consumption remains relatively inelastic in the short to medium term. For network and demand efficiency reasons, Network Tasman also needs to retain off-peak, controlled, night, and summer kWh tariff rates at substantial discounts to peak and uncontrolled rates.

As discussed in section 4, Network Tasman has used an LRMC model as a reference for the peak prices set for each of our mass-market consumers. We have also reduced the prices of our off-peak and controlled tariffs.

All residual revenues, not recovered by the tariffs described above are recovered via fixed charges that least distort network use.

The use of fixed capacity or daily charges provides the best means of compensating for under-recoveries, as these cause minimal distortion to consumption patterns at the mass market level. However, until the low user fixed charge regulations have been fully removed, there is a limit on what can be achieved with respect to domestic customers, which forces loadings on variable tariffs.

Network Tasman has also reformed the fixed charges for Group 3 consumers, as discussed earlier in this document. The introduction of a fixed daily charge and a capacity charge are both expected to reduce incentives for Group 3 consumers to distort their network use.

Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to reflect the economic value of services.

This principle supports end users negotiating a lower price where they would otherwise inefficiently curtail demand (or disconnect or not connect in the first place) if faced with standard prices.

The Authority notes in its pricing principles practice note that this principle is often given effect through a prudent discount policy.

Network Tasman doesn't have an explicit prudent discount policy. We note that the TPM has a prudent discount policy. However, unlike transmission customers who are large, sophisticated energy users and whose electricity costs constitutes a relatively significant proportion of their operating costs, most distribution consumers do not fit these characteristics.

Most commercial connections operate in a competitive markets characterised by regular entry and exit. Given the regularity at which businesses enter and exit their respective markets, it would be administratively unworkable for Network Tasman to employ a prudent discount policy for any but its largest connections. Similarly, few connections on our network incur charges of sufficient size to have a material effect on overall lines charges and therefore justify the application of a prudent discount.

The presence of a formal prudent discount policy may also give rise to opportunistic attempts at using the prudent discount policy to gain lower lines charges.

The absence of a formal prudent discount policy does not preclude the possibility of one being granted in appropriate circumstances.

Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to enable price/quality trade-offs.

Network Tasman considers that for mass market consumers (99% of Network Tasman's ICPs) the electrical network is a "general commons" and the notion of offering price quality/trade-offs for a specific mass market consumer(s) has considerable challenges.

Primarily, the challenge relates to the practicality of administering a bespoke set of services for each individual ICP. In practice, the transaction/administrative cost of allowing each mass-market ICP to negotiate a bespoke lines service would be prohibitive. Other than offering a choice of differing capacity levels and adopting time-differentiated and controlled tariff options to mass market consumers, Network Tasman is generally unable to offer other differentiated lines services to one consumer without at the same time providing it to all other consumers sharing the same network assets whether or not they want, or are prepared, to pay for the service.

However, larger customers can contract for different levels of service where they have high levels of asset dedication. Network Tasman's Group 6 consumers have dedicated network requirements, and these requirements are reflected in the assets provided.

Network Tasman has canvassed electricity retailer views (as representatives of their customers) over line pricing previously. Their primary concerns focus on administrative simplicity and pass-through risk rather than on price/quality trade-offs, although the appetite for more sophisticated pricing is growing. We have reflected this desire with our time-of-use pricing for consumer groups 1 and 2.

Network Tasman, as a consumer trust owned distributor, must agree on its Statement of Corporate Intent (SCI) each year with Trustees (who are elected by and represent consumers' interests). The SCI considers company pricing, revenue, and cost targets as well as quality and reliability targets. Performance is regularly reported against these targets to the Trust. The Trustees hold the power to appoint Network Tasman's Directors and be consulted over any major transactions proposed by the company. This structure puts in place a viable feedback loop to the company from consumers and stakeholders.

Finally, the availability of a *profiled connection* as an option for new loads to reduce their capital contributions can provide these new loads with strong incentives to invest in technologies that increase the flexibility of their loads where costly network investments would be required to serve an equivalent 'traditional' inflexible load. This provides new loads with an additional price/quality trade-off.

Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

Network Tasman supports price transparency in the following ways:

- Network Tasman makes commitments to maintain stability and certainty for line prices in its Statement of Corporate Intent with the Network Tasman Trust

- This pricing methodology document offers a detailed account of how Network Tasman sets it prices and the different drivers that affect our prices. The future pricing strategy section of the methodology also provides readers with a signal of how future prices are expected to evolve in the future. The pricing methodology is updated annually.
- Network Tasman is required to publish changes in prices and pricing methodology.
- Network Tasman annually makes available in the public domain (on its website or makes publicly available) its:
  - Statement of Corporate Intent (agreed with Trustee owners)
  - Annual Financial Statements (audited)
  - Pricing Methodology
  - Line prices split into distribution and transmission components
  - Asset management plan
  - DPP Annual Compliance Statements (audited)
  - Information Disclosures (audited)
  - New connections and contributions policy

These documents directly or indirectly provide pricing and cost information and offer a high level of transparency to stakeholders.

8. Future pricing

Electricity usage and generation are continually evolving. In response, Network Tasman is assessing potential improvements to price structures to support consumer choices while maintaining a sustainable electricity network.

As part of developing a forward pricing strategy, Network Tasman has conducted initial research on consumer interest in emerging technologies such as solar panels, battery storage, and electric vehicles. Below are the results of that research and an overview of Network Tasman's next steps in evaluating potential price structure enhancements or alternatives.

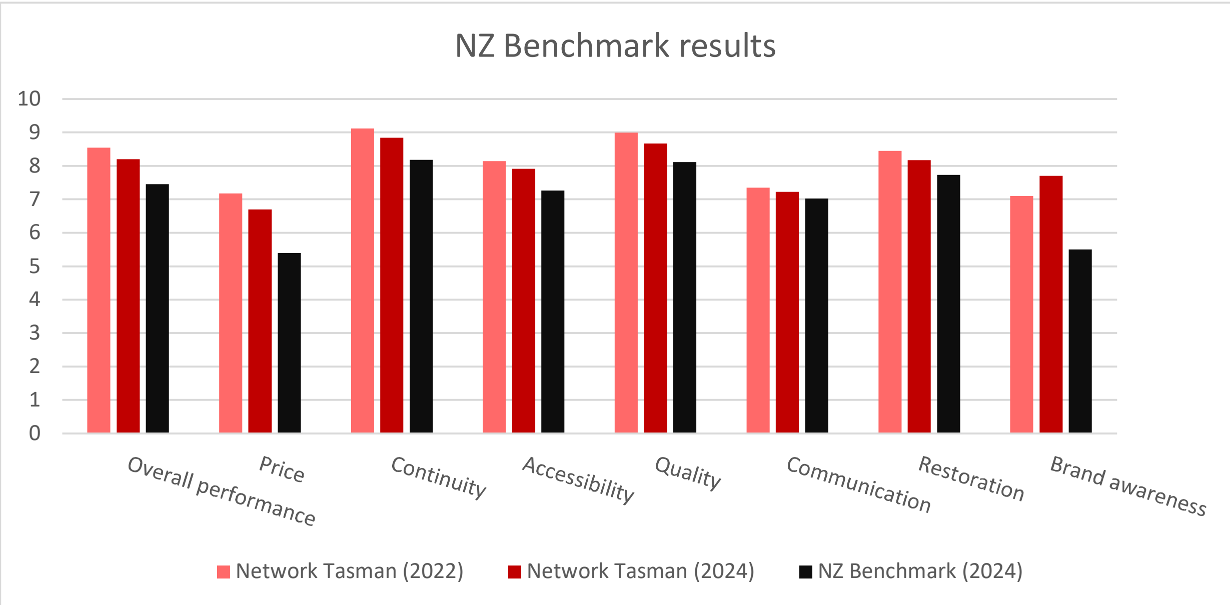
Although Network Tasman does not have a formal pricing strategy as defined in the Information Disclosure Determination, the following summarises its current perspectives on future pricing.

7.1. Consumer perspectives on pricing

Network Tasman conducted a consumer survey in late 2024, which examined a range of issues, including overall satisfaction with our service, willingness to pay for quality improvements and views on price structures.

The survey results showed a high awareness of Network Tasman amongst consumers and a high level of satisfaction with the company's performance about quality of service, continuity and restoration. Consumers gave Network Tasman an overall performance satisfaction rating of 8.2/10.

The survey report compares Network Tasman's results against a national benchmark across a range of categories. Network Tasman exceeded the national benchmark across all eight categories measured.



Consumers were surveyed on price structures. Half of all respondents said they were interested in a peak/off-peak tariff or were already using one. Only 31% stated they were not interested. This result increases the proportion of respondents stating they are interested or already using a time-of-use tariff, from 42% in 2022 to 49% in the current survey.

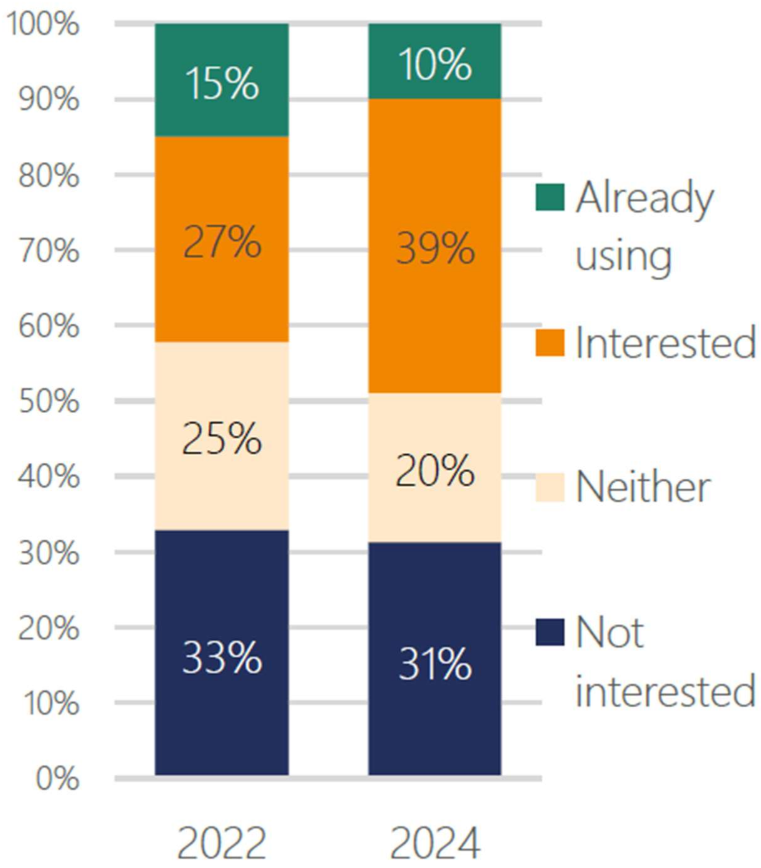
The result of the 2022 survey informed Network Tasman's decision to introduce a mandatory Peak/Off-Peak tariff on 1 April 2023. The current results, in which the proportion of consumer interested in these tariffs has informed our decision to continue rebalancing our Peak/Off-peak price differentials.

The presence of the retail market between distribution prices and the bills consumers receive mitigates the risk of Network Tasman introducing a tariff that some consumers may not wish to receive. Retailers can, and many do, repackage our Peak/Off-peak tariff into a standard flat kWh charge for those consumers who do not want to be subject to a time-varying electricity price.

As such, the flexibility of the retail market means consumers can receive the tariff structure they prefer, be it a flat kWh tariff, a tariff with stronger time-of-use prices, or something in between.

In the absence of a Peak/Off-peak tariff, retailers are limited in their ability to offer consumers a Peak/Off-peak tariff, irrespective of consumer demand. The same dynamic applies to tariffs with strong differentiation between peak and off-peak price differentials.

FIGURE 2: INTEREST IN PEAK VS OFF-PEAK PLAN (2022 AND 2024)



Network Tasman has also surveyed consumer perspectives on price/quality trade-offs. That is, whether they are willing to pay more (or less) in return for higher (or lower) quality lines services, such as faster restoration times or fewer outages.

In practice, Network Tasman is unable to realistically offer services of this nature to the vast majority of its consumers because we are unable to meaningfully differentiate the quality of the service we provide to consumers on an ICP-by-ICP basis. For example, most of our assets are shared across multiple ICPs, making it difficult to meaningfully differentiate service standards across individual ICPs. We continue to discuss price/quality trade-offs with ICPs that use a large proportion of dedicated assets on our network.

The significant majority (75%) of respondents are satisfied with the quality of supply provided by Network Tasman. Only 15% of respondents said they would be prepared to pay more for a better quality service.

7.2. Implications of technological change

Looking to the future, technological change indicates that the way consumers use electricity may change significantly. Solar panels, battery storage, electric vehicles and demand response are forecast become more commonplace. Fixed consumption-based prices are unlikely to promote efficient investment in and use of these technologies.

Although there is significant uncertainty over how popular these technologies will be, how quickly adoption would occur and the ultimate effect these developments will have on the distribution sector, a growing number of consumers have taken an interest in the options becoming available to them.

Network Tasman continues to monitor the commercial implications of solar panels and consider them as part of its future price reform plans. Increasing penetrations of solar PV can cause equity issues if these consumers are able to reduce their lines charges at the expense of other consumers.

The revenue implications of growing EV penetration on our network are less clear as revenues are dependent on when these EVs are charged.

Network Tasman offers all consumer groups very low off-peak consumption rates. Electricity retailers are increasingly passing these low rates on to consumers via attractive off-peak consumption prices. Given the relatively low barriers to consumers charging their vehicles off-peak and the fact that most vehicles are sitting idle overnight, Network Tasman expects most EV owners to charge their vehicles during off-peak periods. As such, Network Tasman expects the revenue growth associated with growing EV penetration to be relatively modest.

Network Tasman has the second highest rooftop solar PV penetration of all distributors in New Zealand. Approximately 6.3% of connections on Network Tasman's network have solar generation and about 4.3% of connections in the combined Network Tasman and Nelson Electricity network areas have an electric vehicle, up from 5.25% and 3.9% twelve months ago, respectively. Although these figures start from a low base they are beginning to exhibit robust growth.

To inform our future asset management plans, Network Tasman commissioned a detailed study into the network's ability to host a range of electric vehicle penetration levels. Our ability to host EVs depends on a range of factors including network age, network design/configuration and where electric vehicles cluster. The broad conclusions of the study are that Network Tasman is well placed to manage expected electric vehicle growth over the short to medium term without requiring significant changes to our existing asset management plans.

Network Tasman took a significant step to modernise its prices by introducing a mandatory Peak/Off-peak tariff for Group 1 and 2 consumers in 2023/24. This tariff gives consumers increasingly strong incentives to shift discretionary load away from periods of network peak demand. Initial price differentials were moderated to manage the bill effect of the new tariff. For 2025/26, Network Tasman has further increased the differential between the peak and off-peak tariffs to provide consumers with stronger incentives to shift load away from the peak.

Network Tasman continues to review its prices for opportunities to improve their cost-reflectivity and will introduce improvements as they are identified, and resources allow.

Appendix A: Glossary

Anytime maximum demand (AMD): The Maximum Demand of the customer measured at the customer's installation during any half hour period during the year.

Advanced Metering Infrastructure (AMI): Electronic meters that measure electricity, record consumption and meter event information electronically, have two-way communication and can be remotely read.

The Code: The *Electricity Industry Participation Code 2010*.

Capacity Charge: A charge based on the capacity (kVA) of a consumer's connection to the network.

Coincident maximum demand (CMD): Demand measure during the system peak.

Distributed Energy Resources (DER): Devices and equipment connected to distribution networks that manage, generate and/or consume electricity, including solar PV, battery storage, hot water cylinders, air-conditioning units and other responsive devices.

Distributed Generator (DG): A party with plant or equipment capable of injecting electricity into Network Tasman's distribution network.

Default Price Path (DPP): The default price path is a form of price-quality regulation administered by the Commerce Commission under Part 4 of the Commerce Act. Price-quality paths constrain the total revenue a distributor can recover from its consumers. The paths also set standards for the quality of service that each distributor must meet. There are two types of price-quality paths relevant to electricity distributors. All businesses start on a 'default' path. If a default path does not suit the particular circumstances of a business, however, it can apply for and propose its own 'customised' path.

EDB: Electricity Distribution Business.

Electricity Authority (EA): The Electricity Authority is an independent Crown entity responsible for overseeing and regulating the New Zealand electricity market.

EV: Electric vehicle.

Fixed Daily Charge: A daily, non-variable fee charged to consumers, regardless of energy use.

Gigawatt-hour (GWh): A unit of energy, being the product of power in watts and time in hours. Used for the measurement of electricity consumption. One GWh is equal to 1,000MWh.

Grid Exit Point (GXP): A point of connection between Transpower's transmission system and the distributor's network.

High-Voltage (HV): Voltage above 1,000 volts.

ICP: Installation Control Point, which is a physical point of connection on a local network which a Distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer.

Incremental Costs: Additional costs associated with connecting new loads or distributed generation to the network.

Kilovolt-ampere (kVA): A measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand.

kilowatt (kW): A measure of electrical power. Used for the measurement of demand during peak periods for the allocation of transmission charges.

kilowatt-hour (kWh): A unit of energy being the product of power in watts and time in hours. Used for the measurement of electricity consumption.

LFC Regulations: Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

LFC tariff: A tariff option that is subject to the LFC Regulations.

Low-Voltage (LV): Voltage of up to 1,000 volts. Generally, 230 or 400 volts for supply to consumers.

Long-run marginal cost (LRMC): The cost of providing an additional unit of electricity when considering future investment in network capacity.

Megavolt-ampere (MVA): A measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand. One MVA is equal to 1,000kVA.

Megawatt-hour (MWh): A unit of energy being the product of power in watts and time in hours. Used for the measurement of electricity consumption. One MWh is equal to 1,000kWh.

Peak/Off-Peak Tariff: A pricing mechanism that charges different rates based on the time of energy usage, with higher rates during peak periods.

Regional Coincident Peak Demand (RCPD): The measure of demand previously used by Transpower for its transmission grid charges. It was measured as the 100 highest half-hour periods of Upper South Island regional demand (measured in kW) from 1 September to 30 August.

Regulatory Asset Base (RAB): The amount that Network Tasman has invested in its regulated network indexed to inflation and adjusted for depreciation.

Small Scale Distributed Generation (SSDG): Small scale distributed generation, i.e., not exceeding 10 kW capacity.

Statement of Corporate Intent (SCI): A document that outlines the overall intentions and objectives that the company will follow for the current financial year and the two following financial years.

Time-of-use (TOU) prices: Time-of-use pricing refers to prices that vary based on the time of consumption (or use). TOU pricing plans have a higher price during “peak demand” and lower prices during “off-peak times”. There can also be a “Shoulder” price which is the time leading into, or out of, the peak demand period.

Transmission Pricing Methodology (TPM): The methodology used by Transpower to set prices for its customers.

Weighted Average Cost of Capital (WACC): The cost of capital is the financial return the Commerce Commission estimates electricity distribution businesses may earn from their regulated businesses. The WACC is used by the Commission to set revenue limits for electricity lines businesses.

Appendix B: Information Disclosure requirements

Requirement	ID reference	Network Tasman pricing methodology reference
Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable.	2.4.1(1)	Refer to sections 2-4.
Describes any changes in prices and target revenues.	2.4.1(2)	Refer to sections 2-4.
Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any).	2.4.1(3)	Refer to sections 5 and 6.
Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	2.4.1(4)	Refer to section 8.
Changes in pricing methodology.	2.4.2	Changes are discussed throughout the document where appropriate.
Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group.	2.4.3(1)	Refer to sections 3 and 4.
Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles.	2.4.3(2)	Refer to section 7.

State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	2.4.3(3)	Refer to section 3.
Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	2.4.3(4)	Refer to section 3.
State the consumer groups for whom prices have been set, and describe: (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups	2.4.3(5)	Refer to section 2.
If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons.	2.4.3(6)	Refer to section 2.
Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way	2.4.3(7)	Refer to section 3.
State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	2.4.3(8)	Refer to Appendix E.
If the EDB has a pricing strategy: (1) explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set.	2.4.4	Refer to section 8.

(2) explain how and why prices for each consumer group are expected to change as a result of the pricing strategy (3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.		
Describe the approach to setting prices for non-standard contracts, including: (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts. (b) how the EDB determines whether to use a non-standard contract, including any criteria used. (c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles.	2.4.5(1)	Refer to section 5.
Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted, including: (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	2.4.5(2)	Refer to section 5.
Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- (a) prices; and	2.4.5(3)	Refer to section 6.

(b) value, structure and rationale for any payments to the owner of the distributed generation		

Appendix C: Cost allocators by load group

Consumer Group	ICPs	Coincident maximum demand	Capacity (fused)	Capacity (transformer)	Total consumption	Allocated RAB
	#	kW	kVA	kVA	kWh	$(m)
Group 1	40,520	63,565	607,797	213,118	273,030,898	$114.67
Group 2	3,085	21,886	139,652	139,652	108,538,381	$55.85
Group 3	203	26,151	80,910	123,230	160,368,623	$47.69
Group 6	2	13,653	N/A	N/A	103,388,036	$2.20
Total	43,8110	125,256	828,359	476,000	645,325,938	$220.42

Appendix D: Network Tasman prices effective from 01 April 2025

				2024-25					2025-26				
Price description	Price Code	Count	Unit of measure	Distribution price	Transmission price	Pass through price	Delivery price	Discount price	Distribution price	Transmission price	Pass through price	Delivery price	Discount price
Metered connections 15-150 kVA capacity													
Low-Use Residential (<8,000 kWh pa) 15 kVA connections. Price Category 1RL													
Daily fixed price	1RL	19,229	$/day	0.3799	0.2185	0.0016	**0.6000**	0.0000	0.4270	0.3210	0.0020	**0.7500**	0.0000
Uncontrolled	1RLANY	4,778	$/kWh	0.0670	0.0066	0.0009	**0.0745**	0.0320	0.0778	0.0000	0.0011	**0.0789**	0.0345
Day (of day/night)	1RLDAY	139	$/kWh	0.0771	0.0066	0.0012	**0.0849**	0.0385	0.0902	0.0000	0.0015	**0.0917**	0.0420
Default	1RLDEF	663	$/kWh	0.0670	0.0066	0.0009	**0.0745**	0.0320	0.0806	0.0000	0.0011	**0.0817**	0.0362
Night	1RLNIT	1,464	$/kWh	0.0262	0.0066	0.0003	**0.0331**	0.0059	0.0273	0.0000	0.0004	**0.0277**	0.0039
Off Peak	1RLOFP	13,843	$/kWh	0.0477	0.0066	0.0009	**0.0552**	0.0196	0.0493	0.0000	0.0011	**0.0504**	0.0172
Peak	1RLPEK	13,838	$/kWh	0.0854	0.0066	0.0009	**0.0929**	0.0438	0.1031	0.0000	0.0011	**0.1042**	0.0498
Controlled water	1RLWSR	15,021	$/kWh	0.0360	0.0066	0.0005	**0.0431**	0.0122	0.0323	0.0000	0.0006	**0.0329**	0.0069
Generation Export	1RLGEN	1,505	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Standard use Residential (>8,000 kWh pa) 15kVA connections. Price Category 1RS													
Daily fixed price	1RS	17,185	$/day	0.7534	0.3644	0.0032	**1.1210**	0.0000	0.8870	0.3210	0.0040	**1.2120**	0.0000
Uncontrolled	1RSANY	4,824	$/kWh	0.0500	0.0000	0.0008	**0.0508**	0.0320	0.0569	0.0000	0.0010	**0.0579**	0.0345
Day (of day/night)	1RSDAY	155	$/kWh	0.0601	0.0000	0.0011	**0.0612**	0.0385	0.0693	0.0000	0.0014	**0.0707**	0.0420
Default	1RSDEF	563	$/kWh	0.0500	0.0000	0.0008	**0.0508**	0.0320	0.0597	0.0000	0.0010	**0.0607**	0.0362
Night	1RSNIT	1,373	$/kWh	0.0092	0.0000	0.0002	**0.0094**	0.0059	0.0064	0.0000	0.0003	**0.0067**	0.0039
Off Peak	1RSOFP	11,843	$/kWh	0.0307	0.0000	0.0008	**0.0315**	0.0196	0.0284	0.0000	0.0010	**0.0294**	0.0172
Peak	1RSPEK	11,837	$/kWh	0.0684	0.0000	0.0008	**0.0692**	0.0438	0.0822	0.0000	0.0010	**0.0832**	0.0498
Controlled water	1RSWSR	13,516	$/kWh	0.0190	0.0000	0.0004	**0.0194**	0.0122	0.0114	0.0000	0.0005	**0.0119**	0.0069
Generation Export	1RSGEN	1,039	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Non-Residential 15kVA connections. Price Category 1GL													
Daily fixed price	1GL	3,665	$/day	0.7534	0.3644	0.0032	**1.1210**	0.0000	0.8870	0.3210	0.0040	**1.2120**	0.0000
Uncontrolled	1GLANY	963	$/kWh	0.0500	0.0000	0.0008	**0.0508**	0.0320	0.0569	0.0000	0.0010	**0.0579**	0.0345
Day (of day/night)	1GLDAY	76	$/kWh	0.0601	0.0000	0.0011	**0.0612**	0.0385	0.0693	0.0000	0.0014	**0.0707**	0.0420
Default	1GLDEF	273	$/kWh	0.0500	0.0000	0.0008	**0.0508**	0.0320	0.0597	0.0000	0.0010	**0.0607**	0.0362
Night	1GLNIT	132	$/kWh	0.0092	0.0000	0.0002	**0.0094**	0.0059	0.0064	0.0000	0.0003	**0.0067**	0.0039
Off Peak	1GLOFP	2,423	$/kWh	0.0307	0.0000	0.0008	**0.0315**	0.0196	0.0284	0.0000	0.0010	**0.0294**	0.0172
Peak	1GLPEK	2,423	$/kWh	0.0684	0.0000	0.0008	**0.0692**	0.0438	0.0822	0.0000	0.0010	**0.0832**	0.0498
Controlled water	1GLWSR	879	$/kWh	0.0190	0.0000	0.0004	**0.0194**	0.0122	0.0114	0.0000	0.0005	**0.0119**	0.0069
Generation Export	1GLGEN	50	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
General (20-150 kVA) connections. Price Category 2													
Daily capacity price	2	2,952	$/kVA/day	0.0762	0.0422	0.0006	**0.1190**	0.0000	0.0815	0.0437	0.0008	**0.1260**	0.0000
Uncontrolled	2ANY	732	$/kWh	0.0553	0.0000	0.0008	**0.0561**	0.0287	0.0564	0.0000	0.0010	**0.0574**	0.0289
Day (of day/night)	2DAY	344	$/kWh	0.0663	0.0000	0.0008	**0.0671**	0.0344	0.0776	0.0000	0.0010	**0.0786**	0.0397
Default	2DEF	278	$/kWh	0.0553	0.0000	0.0008	**0.0561**	0.0287	0.0592	0.0000	0.0010	**0.0602**	0.0303
Night	2NIT	424	$/kWh	0.0204	0.0000	0.0000	**0.0204**	0.0106	0.0079	0.0000	0.0000	**0.0079**	0.0040
Off Peak	2OFP	1,680	$/kWh	0.0352	0.0000	0.0008	**0.0360**	0.0182	0.0279	0.0000	0.0010	**0.0289**	0.0143
Peak	2PEK	1,680	$/kWh	0.0684	0.0000	0.0008	**0.0692**	0.0355	0.0758	0.0000	0.0010	**0.0768**	0.0388
Controlled water	2WSR	686	$/kWh	0.0198	0.0000	0.0004	**0.0202**	0.0103	0.0102	0.0000	0.0005	**0.0107**	0.0052
Generation Export	2GEN	185	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Residential Low Fixed (20 and 30 kVA capacity) connections. Price Category 2LLFC													
Daily capacity price	2LLFC	62	$/day	0.0000	0.5983	0.0017	**0.6000**	0.0000	0.0000	0.7479	0.0021	**0.7500**	0.0000
Uncontrolled	2LANY	34	$/kWh	0.1360	0.0000	0.0013	**0.1373**	0.0287	0.1364	0.0000	0.0016	**0.1380**	0.0289
Day (of day/night)	2LDAY	5	$/kWh	0.1470	0.0000	0.0013	**0.1483**	0.0344	0.1576	0.0000	0.0016	**0.1592**	0.0397
Default	2LDEF	4	$/kWh	0.1360	0.0000	0.0013	**0.1373**	0.0287	0.1392	0.0000	0.0016	**0.1408**	0.0303
Night	2LNIT	9	$/kWh	0.1011	0.0000	0.0005	**0.1016**	0.0106	0.0879	0.0000	0.0006	**0.0885**	0.0040
Off Peak	2LOFP	29	$/kWh	0.1159	0.0000	0.0013	**0.1172**	0.0182	0.1079	0.0000	0.0016	**0.1095**	0.0143
Peak	2LPEK	29	$/kWh	0.1491	0.0000	0.0013	**0.1504**	0.0355	0.1558	0.0000	0.0016	**0.1574**	0.0388
Controlled water	2LWSR	31	$/kWh	0.1005	0.0000	0.0009	**0.1014**	0.0103	0.0902	0.0000	0.0011	**0.0913**	0.0052
Generation Export	2LGEN	5	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Residential Low Fixed (40 to 150 kVA capacity) connections. Price Category 2HLFC													
Daily capacity price	2HLFC	5	$/day	0.0000	0.5983	0.0017	**0.6000**	0.0000	0.0000	0.7479	0.0021	**0.7500**	0.0000
Uncontrolled	2HANY	2	$/kWh	0.2441	0.0000	0.0018	**0.2459**	0.0287	0.2507	0.0000	0.0024	**0.2531**	0.0289
Day (of day/night)	2HDAY	0	$/kWh	0.2551	0.0000	0.0018	**0.2569**	0.0344	0.2719	0.0000	0.0024	**0.2743**	0.0397
Default	2HDEF	0	$/kWh	0.2441	0.0000	0.0018	**0.2459**	0.0287	0.2535	0.0000	0.0024	**0.2559**	0.0303
Night	2HNIT	0	$/kWh	0.2092	0.0000	0.0010	**0.2102**	0.0106	0.2022	0.0000	0.0014	**0.2036**	0.0040
Off Peak	2HOFP	4	$/kWh	0.2240	0.0000	0.0018	**0.2258**	0.0182	0.2222	0.0000	0.0024	**0.2246**	0.0143
Peak	2HPEK	4	$/kWh	0.2572	0.0000	0.0018	**0.2590**	0.0355	0.2701	0.0000	0.0024	**0.2725**	0.0388
Controlled water	2HWSR	2	$/kWh	0.2086	0.0000	0.0014	**0.2100**	0.0103	0.2045	0.0000	0.0019	**0.2064**	0.0052
Generation Export	2HGEN	0	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
High Load Factor (Up to 150 kVA) connections. Price Category HLF													
Daily capacity price	HLF	40	$/kVA/day	0.4434	0.0822	0.0044	**0.5300**	0.0842	0.5180	0.0436	0.0055	**0.5671**	0.0932
Uncontrolled	HLFANY	3	$/kWh	0.0187	0.0000	0.0002	**0.0189**	0.0097	0.0187	0.0000	0.0003	**0.0190**	0.0096
Day (of day/night)	HLFDAY	3	$/kWh	0.0225	0.0000	0.0002	**0.0227**	0.0117	0.0275	0.0000	0.0003	**0.0278**	0.0141
Default	HLFDEF	5	$/kWh	0.0187	0.0000	0.0002	**0.0189**	0.0097	0.0196	0.0000	0.0003	**0.0199**	0.0100
Night	HLFNIT	4	$/kWh	0.0055	0.0000	0.0002	**0.0057**	0.0029	0.0055	0.0000	0.0003	**0.0058**	0.0028
Off Peak	HLFOFP	29	$/kWh	0.0144	0.0000	0.0002	**0.0146**	0.0075	0.0143	0.0000	0.0003	**0.0146**	0.0073
Peak	HLFPEK	29	$/kWh	0.0226	0.0000	0.0002	**0.0228**	0.0117	0.0226	0.0000	0.0003	**0.0229**	0.0116
Controlled water	HLFWSR	7	$/kWh	0.0086	0.0000	0.0002	**0.0088**	0.0045	0.0086	0.0000	0.0003	**0.0089**	0.0044
Generation Export	HLFGEN	2	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000

Price description	Price Code	Count	Unit of measure	Distribution price	Transmission price	Pass through price	Delivery price	Discount price	Distribution price	Transmission price	Pass through price	Delivery price	Discount price
Large Commercial ≥150 kVA capacity, TOU metered (Group 3)													
Category 3.1													
Daily fixed price	FXD3.1	40	$/day	2.0000	0.0000	0.0000	**2.0000**	0.2300	5.4000	0.0000	0.0000	**5.4000**	0.6912
Anytime demand (Distribution)	AnyDem31	40	$/kVA/day	0.1219	0.0000	0.0063	**0.1282**	0.0140	0.1475	0.0000	0.0079	**0.1554**	0.0189
Anytime demand (Transmission)	ANY_T3.1	40	$/kVA/day	0.0000	0.0973	0.0000	**0.0973**	0.0000	0.0000	0.0689	0.0000	**0.0689**	0.0000
Daily capacity price(1)	CAP3.1	4	$/kVA/day	0.0000	0.0130	0.0000	**0.0130**	0.0000	0.0000	0.0300	0.0000	**0.0300**	0.0000
Summer day	SD31	40	$/kWh	0.0033	0.0000	0.0000	**0.0033**	0.0010	0.0033	0.0000	0.0000	**0.0033**	0.0008
Summer night	SN31	40	$/kWh	0.0033	0.0000	0.0000	**0.0033**	0.0010	0.0033	0.0000	0.0000	**0.0033**	0.0008
Winter day	WD31	40	$/kWh	0.0166	0.0000	0.0000	**0.0166**	0.0049	0.0201	0.0000	0.0000	**0.0201**	0.0050
Winter night	WN31	40	$/kWh	0.0033	0.0000	0.0000	**0.0033**	0.0010	0.0033	0.0000	0.0000	**0.0033**	0.0008
Generation	3.1GEN	40	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Category 3.3													
Daily fixed price	FXD3.3	2	$/day	2.0000	0.0000	0.0000	**2.0000**	0.2300	5.4000	0.0000	0.0000	**5.4000**	0.6912
Anytime demand (Distribution)	AnyDem33	2	$/kVA/day	0.1463	0.0000	0.0063	**0.1526**	0.0168	0.1653	0.0000	0.0079	**0.1732**	0.0212
Anytime demand (Transmission)	ANY_T3.3	2	$/kVA/day	0.0000	0.0973	0.0000	**0.0973**	0.0000	0.0000	0.0689	0.0000	**0.0689**	0.0000
Daily capacity price(1)	CAP3.3	6	$/kVA/day	0.0000	0.0130	0.0000	**0.0130**	0.0000	0.0000	0.0300	0.0000	**0.0300**	0.0000
Summer day	SD33	2	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Summer night	SN33	2	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Winter day	WD33	2	$/kWh	0.0626	0.0000	0.0000	**0.0626**	0.0184	0.0689	0.0000	0.0000	**0.0689**	0.0173
Winter night	WN33	2	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Generation	3.3GEN	2	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Category 3.4													
Daily fixed price	FXD3.4	187	$/day	2.0000	0.0000	0.0000	**2.0000**	0.2300	5.4000	0.0000	0.0000	**5.4000**	0.6912
Anytime demand (Distribution)	AnyDem34	187	$/kVA/day	0.1562	0.0000	0.0063	**0.1625**	0.0180	0.1765	0.0000	0.0079	**0.1844**	0.0226
Anytime demand (Transmission)	ANY_T3.4	187	$/kVA/day	0.0000	0.0973	0.0000	**0.0973**	0.0000	0.0000	0.0689	0.0000	**0.0689**	0.0000
Daily capacity price(1)	CAP3.4	187	$/kVA/day	0.0000	0.0130	0.0000	**0.0130**	0.0000	0.0000	0.0300	0.0000	**0.0300**	0.0000
Summer day	SD34	187	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Summer night	SN34	187	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Winter day	WD34	187	$/kWh	0.0626	0.0000	0.0000	**0.0626**	0.0184	0.0689	0.0000	0.0000	**0.0689**	0.0173
Winter night	WN34	187	$/kWh	0.0107	0.0000	0.0000	**0.0107**	0.0031	0.0102	0.0000	0.0000	**0.0102**	0.0026
Generation	3.4GEN	187	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Category 3.5													
Daily fixed price	FXD3.5	6	$/day	2.0000	0.0000	0.0000	**2.0000**	0.2300	5.4000	0.0000	0.0000	**5.4000**	0.6912
Anytime demand (Distribution)	AnyDem35	6	$/kVA/day	0.1463	0.0000	0.0063	**0.1526**	0.0168	0.1653	0.0000	0.0079	**0.1732**	0.0212
Anytime demand (Transmission)	ANY_T3.5	6	$/kVA/day	0.0000	0.0973	0.0000	**0.0973**	0.0000	0.0000	0.0689	0.0000	**0.0689**	0.0000
Daily capacity price(1)	CAP3.5	2	$/kVA/day	0.0000	0.0130	0.0000	**0.0130**	0.0000	0.0000	0.0300	0.0000	**0.0300**	0.0000
Summer day	SD35	6	$/kWh	0.0085	0.0000	0.0000	**0.0085**	0.0025	0.0081	0.0000	0.0000	**0.0081**	0.0020
Summer night	SN35	6	$/kWh	0.0085	0.0000	0.0000	**0.0085**	0.0025	0.0081	0.0000	0.0000	**0.0081**	0.0020
Winter day	WD35	6	$/kWh	0.0505	0.0000	0.0000	**0.0505**	0.0148	0.0556	0.0000	0.0000	**0.0556**	0.0140
Winter night	WN35	6	$/kWh	0.0085	0.0000	0.0000	**0.0085**	0.0025	0.0081	0.0000	0.0000	**0.0081**	0.0020
Generation	3.5GEN	6	$/kWh	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Power factor charge (where applies)													
All group 3 categories	kVAr3.4	3	$/kVAr/day	0.3298	0.0000	0.0000	**0.3298**	0.0000	0.3628	0.0000	0.0000	**0.3628**	0.0000
Individually priced categories													
Cat 6.1 - Annual charge	6.1	1	$ per annum	255,139	1,119,701	836	**1,375,674**	27,280	265,344	1,279,394	701	**1,545,439**	27,280
Cat 6.2 - Annual charge	6.2	1	$ per annum	273,443	189,266	836	**463,546**	40,552	284,382	209,703	701	**494,787**	40,552
Cat CB - Annual charge	CobbLine	1	$ per annum	1,676,562	234,833	0	**1,911,396**	0	1,684,329	290,723	0	**1,975,052**	0
Cat MAT - Annual charge	MAT	1	$ per annum	10,774	2,882	0	**13,656**	0	13,651	2,394	0	**16,045**	0
Embedded Network	NEL	1	$ per annum	0	1,558,349	0	**1,558,349**	0	0	1,908,600	0	**1,908,600**	0
Individual categories	EAL1	4	$/MWh 1	0.0000	0.0000	0.1562	**0.1562**	0	0.0000	0.0000	0.1923	**0.1923**	0
Unmetered connections (Group 0):Low capacity: Electric fences, communications etc													
Daily fixed price	0UNM	76	$/day	0.5371	0.0776	0.0053	**0.6200**	0.0000	0.5578	0.0776	0.0066	**0.6420**	0.0000
Unmetered connections (Group 0): Streetlighting - General													
Streetlight only connection	0S	Total	$/day	0.0000	0.0000	0.0000	**0.0000**	0.0000	0.0000	0.0000	0.0000	**0.0000**	0.0000
Capacity price for streetlights	0STL	0	$/W/day	0.00104	0.00016	0.00001	**0.00121**	0.0000	0.00109	0.00016	0.00001	**0.00126**	0.0000

Appendix E: Proportion of target revenue collected via each price component

Price description	Price Code	Connections with this price	Unit of measure	Distribution	Transmission	Pass through & recoverable	Total
Metered connections 15-150 kVA capacity							
Low-Use Residential (<8,000 kWh pa) 15 kVA connections. Price Category 1RL							
Daily fixed price	1RL	19,229	$/day	6.4%	4.8%	0.0%	11.2%
Uncontrolled	1RLANY	4,778	$/kWh	1.6%	0.0%	0.0%	1.7%
Day (of day/night)	1RLDAY	139	$/kWh	0.1%	0.0%	0.0%	0.1%
Default	1RLDEF	663	$/kWh	0.5%	0.0%	0.0%	0.5%
Night	1RLNIT	1,464	$/kWh	0.1%	0.0%	0.0%	0.1%
Off Peak	1RLOFP	13,843	$/kWh	1.7%	0.0%	0.1%	1.7%
Peak	1RLPEK	13,838	$/kWh	3.3%	0.0%	0.1%	3.3%
Controlled water	1RLWSR	15,021	$/kWh	1.4%	0.0%	0.0%	1.5%
Generation Export	1RLGEN	1,505	$/kWh	0.0%	0.0%	0.0%	0.0%
Standard use Residential (>8,000 kWh pa) 15kVA connections. Price Category 1RS							
Daily fixed price	1RS	17,185	$/day	11.8%	4.3%	0.1%	16.1%
Uncontrolled	1RSANY	4,824	$/kWh	1.2%	0.0%	0.1%	1.3%
Day (of day/night)	1RSDAY	155	$/kWh	0.1%	0.0%	0.0%	0.1%
Default	1RSDEF	563	$/kWh	0.4%	0.0%	0.0%	0.4%
Night	1RSNIT	1,373	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	1RSOFP	11,843	$/kWh	0.9%	0.0%	0.1%	0.9%
Peak	1RSPEK	11,837	$/kWh	2.8%	0.0%	0.1%	2.9%
Controlled water	1RSWSR	13,516	$/kWh	0.3%	0.0%	0.0%	0.4%
Generation Export	1RSGEN	1,039	$/kWh	0.0%	0.0%	0.0%	0.0%
Non-Residential 15kVA connections. Price Category 1GL							
Daily fixed price	1GL	3,665	$/kWh	2.6%	0.9%	0.0%	3.5%
Uncontrolled	1GLANY	963	$/kWh	0.2%	0.0%	0.0%	0.2%
Day (of day/night)	1GLDAY	76	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	1GLDEF	273	$/kWh	0.1%	0.0%	0.0%	0.1%
Night	1GLNIT	132	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	1GLOFP	2,423	$/kWh	0.1%	0.0%	0.0%	0.2%
Peak	1GLPEK	2,423	$/kWh	0.6%	0.0%	0.0%	0.6%
Controlled water	1GLWSR	879	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	1GLGEN	50	$/kWh	0.0%	0.0%	0.0%	0.0%
General (20-150 kVA) connections. Price Category 2							
Daily fixed price	2	2,952	$/kVA/day	8.5%	4.6%	0.1%	13.2%
Uncontrolled	2ANY	732	$/kWh	1.1%	0.0%	0.0%	1.1%
Day (of day/night)	2DAY	344	$/kWh	1.1%	0.0%	0.0%	1.1%
Default	2DEF	278	$/kWh	0.4%	0.0%	0.0%	0.4%
Night	2NIT	424	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	2OFP	1,680	$/kWh	0.7%	0.0%	0.0%	0.7%
Peak	2PEK	1,680	$/kWh	2.6%	0.0%	0.1%	2.7%
Controlled water	2WSR	686	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	2GEN	185	$/kWh	0.0%	0.0%	0.0%	0.0%
Residential Low Fixed (20 and 30 kVA capacity) conne		0					
Daily fixed price	2LLFC	62	$/day	0.0%	0.0%	0.0%	0.0%
Uncontrolled	2LANY	34	$/kWh	0.0%	0.0%	0.0%	0.0%
Day (of day/night)	2LDAY	5	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	2LDEF	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	2LNIT	9	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	2LOFP	29	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	2LPEK	29	$/kWh	0.0%	0.0%	0.0%	0.0%
Controlled water	2LWSR	31	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	2LGEN	5	$/kWh	0.0%	0.0%	0.0%	0.0%
Residential Low Fixed (40 to 150 kVA capacity) connections. Price Category 2HLFC							
Daily fixed price	2HLFC	5	$/day	0.0%	0.0%	0.0%	0.0%
Uncontrolled	2HANY	2	$/kWh	0.0%	0.0%	0.0%	0.0%
Day (of day/night)	2HDAY	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	2HDEF	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	2HNIT	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	2HOFP	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	2HPEK	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Controlled water	2HWSR	2	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	2HGEN	0	$/kWh	0.0%	0.0%	0.0%	0.0%
High Load Factor (Up to 150 kVA) connections. Price Category HLF							
Daily fixed price	HLF	40	$/kVA/day	0.9%	0.1%	0.0%	1.0%
Uncontrolled	HLFANY	3	$/kWh	0.0%	0.0%	0.0%	0.0%
Day (of day/night)	HLFDAY	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	HLFDEF	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	HLFNIT	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	HLFOFP	29	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	HLFPEK	29	$/kWh	0.0%	0.0%	0.0%	0.0%
Controlled water	HLFWSR	7	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	HLFGEN	2	$/kWh	0.0%	0.0%	0.0%	0.0%

Price description	Price Code	Connections with this price	Unit of measure	Distribution	Transmission	Pass through & recoverable	Total
Large Commercial ≥150 kVA capacity, TOU metered (Group 3)							
Category 3.1							
Anytime kVA demand	AnyDem31	4	$/kVA/day	0.2%	0.0%	0.0%	0.2%
Anytime kVA demand (Transmission)	ANY_T3.1	4	$/kVA/day	0.0%	0.1%	0.0%	0.1%
Capacity Charge	Cap3.1	4	$/kVA/day	0.0%	0.1%	0.0%	0.1%
Daily Charge	Fxd3.1	4	$/day	0.0%	0.0%	0.0%	0.0%
Summer day	SD31	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Summer night	SN31	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Winter day	WD31	4	$/kWh	0.1%	0.0%	0.0%	0.1%
Winter night	WN31	4	$/kWh	0.0%	0.0%	0.0%	0.0%
Category 3.3							
Anytime kVA demand	AnyDem33	6	$/kVA/day	0.3%	0.0%	0.0%	0.3%
Anytime kVA demand (Transmission)	ANY_T3.3	6	$/kVA/day	0.0%	0.1%	0.0%	0.1%
Capacity Charge	Cap3.3	6	$/kVA/day				
Daily Charge	Fxd3.3	6	$/day				
Summer day	SD33	6	$/kWh	0.1%	0.0%	0.0%	0.1%
Summer night	SN33	6	$/kWh	0.0%	0.0%	0.0%	0.0%
Winter day	WD33	6	$/kWh	0.2%	0.0%	0.0%	0.2%
Winter night	WN33	6	$/kWh	0.0%	0.0%	0.0%	0.0%
Category 3.4							
Anytime kVA demand	AnyDem34	192	$/kVA/day	6.1%	0.0%	0.3%	6.4%
Anytime kVA demand (Transmission)	ANY_T3.4	192	$/kVA/day	0.0%	2.7%	0.0%	2.7%
Capacity Charge	Cap3.4	192	$/kVA/day	0.0%	1.7%	0.0%	1.7%
Daily Charge	Fxd3.4	192	$/day	0.7%	0.0%	0.0%	0.7%
Summer day	SD34	192	$/kWh	0.8%	0.0%	0.0%	0.8%
Summer night	SN34	192	$/kWh	0.3%	0.0%	0.0%	0.3%
Winter day	WD34	192	$/kWh	4.6%	0.0%	0.0%	4.6%
Winter night	WN34	192	$/kWh	0.3%	0.0%	0.0%	0.3%
Category 3.5							
Anytime kVA demand	AnyDem35	2	$/kVA/day	0.3%	0.0%	0.0%	0.3%
Anytime kVA demand (Transmission)	ANY_T3.5	2	$/kVA/day	0.0%	0.2%	0.0%	0.2%
Capacity Charge	Cap3.5	2	$/kVA/day	0.0%	0.1%	0.0%	0.1%
Daily Charge	Fxd3.5	2	$/day	0.0%	0.0%	0.0%	0.0%
Summer day	SD35	2	$/kWh	0.1%	0.0%	0.0%	0.1%
Summer night	SN35	2	$/kWh	0.0%	0.0%	0.0%	0.0%
Winter day	WD35	2	$/kWh	0.3%	0.0%	0.0%	0.3%
Winter night	WN35	2	$/kWh	0.0%	0.0%	0.0%	0.0%
Power factor charge (where applies)							
All group 3 categories	kVAr	3	$/kVAr/day	0.0%	0.0%	0.0%	0.0%
Individually priced category (Group 6)							
Cat 6.1 - Annual charge	6.1	1	$ per annum	0.5%	2.7%	0.0%	3.2%
Cat 6.2 - Annual charge	6.2	1	$ per annum	0.5%	0.4%	0.0%	1.0%
Cat CB - Annual charge	CB	1	$ per annum	3.5%	0.6%	0.0%	4.1%
Cat MAT - Annual charge	MAT	1	$ per annum	0.0%	0.0%	0.0%	0.0%
Cat NEL - Annual charge	NEL	1	$ per annum	0.0%	4.0%	0.0%	4.0%
EAL Levy	EAL[1]		$/MWh [1]	0.0%	0.0%	0.0%	0.0%
Unmetered connections (Group 0):Low capacity: Electric fences, communications etc							
Daily fixed price	0UNM	65	$/day	0.0%	0.0%	0.0%	0.0%
Unmetered connections (Group 0): Streetlighting - General							
Streetlight only connection	0S	22	$/day	0.0%	0.0%	0.0%	0.0%
Capacity price for streetlights	0STL	0	$/W/day	0.4%	0.1%	0.0%	0.4%

Appendix F: Methodology for allocating settlement residual rebates

In November 2022, the Electricity Authority amended the Code to require distributors to pass through settlement residual rebates (otherwise known as *losses and constraints excess* payments) to their customers.

The newly amended Code states the purpose of the requirement to pass-on settlement residue is to allocate settlement residue to customers in proportion to the transmission charges paid by those customers in respect of each connection location.

Distributors must allocate these residues monthly to customers that pay lines charges directly to Network Tasman.

Distributors must apply a methodology for allocating settlement residue to its customers that gives effect to the purpose of the Code amendment.

Network Tasman's methodology for allocating monthly settlement residues received from Transpower is described below.

Settlement residual for a given connection location is allocated to customers in proportion to the transmission charges paid by each customer to Network Tasman at that connection location.

A customer's monthly transmission charges at a connection location is calculated by multiplying the transmission prices published on Network Tasman's regulated price schedule by the billing quantities used by that customer at the connection location for the month in question.

For the avoidance of doubt, billing quantities refer to the initial quantities used by Network Tasman to invoice the customer for the relevant month and connection location.

The settlement residual received by Network Tasman for a given location will be allocated to customers in proportion to their contribution to the total monthly transmission charge received from all customers at that connection location.

The formula below summarises the methodology to be used:

$$\begin{aligned} &Monthly\ settlement\ residual\ payment_{x,y} \\ &\qquad = Monthly\ settlement\ residual_{y} \times \left(\frac{Monthly\ transmission\ charge\ paid_{x,y}}{\sum_x Monthly\ transmission\ charge\ paid_{y}}\right) \end{aligned}$$

Where:

x = customer

y = connection location

Monthly settlement residual$_y$ = Monthly settlement residual payment from Transpower to Network Tasman for connection location y

Monthly transmission charge paid$_{x,y}$ = Transmission charge paid by customer x to Network Tasman at connection location y

Payments are based on initial billing quantities and will not be subject to adjustments. Payments to customers are made monthly.

Appendix G – Cost allocators

Direct network costs

Direct network costs comprise of network operations and maintenance costs, depreciation on network assets and direct overheads. These costs are grouped into to the following asset classes:

- LV Lines/cables (230V/400V)
- Distribution transformers
- 11kV lines/cables
- 11kV lines/cables – dedicated
- Zone substations
- Sub-transmission lines/cables
- Other/non-specific

There are different methodologies for grouping each category of direct network costs into the asset classes above. The tables below set out how these costs are allocated to each asset class.

Operations and maintenance

	Asset group										
Cost	**400V Lines General**	**Distribution Transformers**	**11kV Lines General**	**11kV Lines Dedicated**	**Zone Subs**	**Sub transmission lines**	**Other non specific**	**Dedicated Network**	**Generator 1**	**Generator 2**	**Allocator for shared costs**
O/H Conductor 33kV & 66kV						✓		✓		✓	RAB ratio
U/G Cables 33kV						✓		✓			RAB ratio
Distribution Transformers		✓									N/A
O/H Conductor 11kV & 22kV			✓								N/A
O/H Conductor 400v	✓										N/A
U/G Cables 11kV & 22kV			✓								N/A
U/G Cables 400v	✓										N/A
Field Switchgear & fuses			✓								N/A

Field regulators			✓								N/A
All Poles	✓		✓			✓		✓		✓	Line length
Line corridors	✓		✓			✓		✓			Line length
Line Corridors - Rivers			✓								N/A
Tree Cutting	✓		✓	✓		✓					Line length
Tree Regulations Removals	✓		✓	✓		✓					Line length
Fall Distance Tree Removal	✓		✓	✓		✓					Line length
Access Tracks	✓		✓	✓		✓					Line length
Substation Transformers					✓			✓			RAB ratio
Distribution Subs		✓									N/A
Substation Switchgear & fuses					✓				✓		N/A
Substation Buildings & Switchyards					✓			✓			RAB ratio
Substation SCADA					✓			✓			RAB ratio
LCP Transmitters	✓										N/A
SCADA Master Station					✓						N/A
SCADA & Ripple Back Up	✓										N/A
Operations General	✓		✓			✓		✓			Line length
Service Boxes	✓										N/A
Substation Batteries					✓						N/A
Field ABS Isolators			✓								N/A
Dist MDI Reads & Checks		✓									N/A
Contractor H&S Auditing			✓								N/A
Communications Networks			✓								N/A
Audits			✓								N/A
Audit Recoveries			✓								N/A
Connection Policy Alterations	✓										N/A
Voltage Support			✓								N/A
Faults Services - Network							✓				N/A
Faults Services-Vegetation			✓								N/A
Fault Recoveries			✓								N/A
Service Level Payments							✓				N/A
Portable Generator Costs			✓								N/A
Emergency Maintenance			✓								N/A
AR, Reg, Line MDI Reads							✓				N/A
Sub VRR Settings					✓						N/A

Transformer Changeouts		✓									N/A
Emergency Stock Mgmt							✓				N/A
Connection Assets	✓										N/A
Management Fee	✓	✓	✓		✓	✓					RAB ratio
Training							✓				N/A
Traffic Mgmt Costs	✓		✓			✓		✓			Line length
Line Surveys	✓		✓			✓		✓			Line length

Other/non-specific costs are allocated across the other categories in proportion to their total allocated costs (pre-allocation of other/non-specific costs)

Depreciation (and RAB)

Asset category	Asset group									
	400V Lines General	Distribution Transformers	11kV Lines General	11kV Lines Dedicated	Zone Substations	Sub transmission lines	Other non specific	Dedicated Networks	Generator 1	Generator 2
Sub-transmission										
66kV Lines						✓				✓
33 kV Lines						✓		✓		
33kV Cable						✓		✓		
33kV Switchgear						✓		✓		
Zone Substations						✓		✓	✓	✓
Distribution										
11kV Lines			✓					✓		
11kV Cable			✓							
11kV Switchgear			✓							
11kV Transmission Transformers		✓								
11kV Transmission Substations		✓								
400V Lines	✓									
400V Cables	✓									
Customer Equipment	✓									
Meters & Relays							✓			
Street Lights Regulators, Scada							✓			
Inventory							✓			
Non-system fixed assets							✓			

Direct overheads

Direct overheads comprise of overheads related to network operations, network management and vegetation management business units.

These costs are not easily linked to specific asset classes in the manner that operations and maintenance costs are. These costs are allocated to the asset classes outlined above on a prorated basis, in proportion to the total depreciation and operations and maintenance costs allocated to each asset class.

Allocation of direct network costs to consumer groups

With the three cost categories now allocated across the asset classes outlined above, the costs of each asset class are then allocated to each consumer group broadly in proportion to how much of that asset class they use.

Costs are also allocated to large consumers with non-standard contracts with respect to the specific agreements or incumbent approaches.

The cost of 400V lines/cables, 11kV lines/cables, zone substations, and sub-transmission lines/cables are allocated to mass-market consumer groups based on their average annual coincident maximum demand over the previous three years. A three-year average is used to minimise year-on-year volatility.

Costs associated with distribution transformers are allocated to mass-market consumer groups based on estimates of each group's relative transformer capacity.

Group 3 allocations of depreciation (and RAB) for LV lines are adjusted to reflect their lesser reliance on these assets. While most Group 3 connections are supplied at LV, they are often supplied from transformers located on or near their premises.

The adjustment to the RAB and depreciation allocations for LV lines and cables reflects this. These adjustments are set according to management estimates.

Indirect network costs

Indirect network costs comprise of depreciation on non-system assets and overheads for activities that are not directly network-related, such as finance, regulatory/commercial, and corporate costs.

These costs are allocated to mass-market consumer groups in proportion to their total fused capacity. Allocations for non-mass-market consumer groups are made using management estimates.