networktasman
Your consumer-owned electricity distributor

PRICING METHODOLOGY DISCLOSURE

Effective 1 April 2023

Pursuant to Electricity Distribution Information Disclosure Determination 2012. For compliance with Part 2.4.1: Disclosure of pricing methodologies

networktasman
Your consumer owned eletricity distributor

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Schedule 17: Certification for Pricing Methodology Disclosure

We, Michael John McCliskie and Lee Derek Babe 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.

.... Date: 16 March 2023

.... Date: 16 March 2023

1. Introduction

1.1. About Network Tasman

Network Tasman Limited (Network Tasman) owns and operates the electricity distribution network in the wider Nelson and Tasman areas, excluding Nelson Electricity's supply area in Nelson city. Network Tasman's electricity distribution network distributes power to more than 42,000 connections.

Total electricity distributed through the network is 691 GWh, with a peak load of 130 MW[1]. The area covered by the network is diverse, ranging from relatively dense urban areas to remote rural areas.

Network Tasman distributes electricity to residential and commercial consumers within its area from Transpower grid exit points at Stoke, Kikiwa and Murchison.

Network Tasman is wholly owned by a consumer trust - the Network Tasman Trust.

The company's mission is to own and operate efficient, reliable and safe electricity networks and other complementary businesses while increasing consumer value. After consultation with its shareholders, Network Tasman issues an annual statement of corporate intent, which outlines the overall intentions and objectives that the company will follow.

1.2. The purpose of this document

This document sets out the framework of Network Tasman's pricing methodology and contains the information required for compliance with sections 2.4.1 to 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012.

1.3. Overview of this report

This document is structured as follows:

- A description of our pricing for the year commencing 1 April 2023 is set out in Section 2;
- The methodology used to determine Network Tasman's total revenue requirement and its allocation by load group is discussed in Section 3;
- The approach used to derive Network Tasman's prices is set out in Section 4;
- A summary of Network Tasman's use of non-standard contracts is discussed in Section 5;
- Distributed generation pricing is discussed in Section 6;
- An assessment of Network Tasman's pricing methodology against the Electricity Authority's Pricing Principles is set out in Section 7; and
- Network Tasman's future pricing strategy is discussed in Section 8.

Network Tasman's prices are charged to electricity retailers[2] in the wider Nelson and Tasman regions, excluding Nelson Electricity's supply area in Nelson City. Electricity retailers determine how to package

[1] Excluding bulk supply to Nelson Electricity.

[2] There are also a small number of large customers that are direct billed by Network Tasman.

these charges with the energy, metering and other retail costs when setting the retail prices that appear in consumers' power accounts.

Network Tasman's prices cover the cost of its local electricity distribution network, pass-through costs (such as industry levies) and the costs associated with the national transmission grid.

Network Tasman has introduced several price or price-related changes for the coming year. These are discussed where appropriate in the body of the document and include:

- A new methodology for allocating transmission costs to consumer groups to reflect the introduction of a new transmission pricing methodology.
- The introduction of a new Peak/Off-peak tariff for consumer groups 1 and 2.
- The removal of the RCPD charge for Group 3 connections and the use of an anytime maximum demand charge to recover all Group 3 transmission costs.
- The use of an updated measure of coincident maximum demand to allocate direct opex and depreciation across consumer groups.
- The introduction of a new profiled connection category for flexible loads in Network Tasman's capital contributions policy.
- The development of a methodology to pass settlement residue[3] payments through to customers.

In determining our prices, Network Tasman has had regard to many factors; primary among those is the need to recover sufficient revenues to fund the business's ongoing regulated activities whilst also managing the effect of price changes on consumers.

[3] Settlement residue is the balance of funds received by Transpower from the clearing manager, drawn from wholesale market loss and constraint excess (LCE) and FTR market surplus (if any).

2. Our pricing from 1 April 2023

2.1. Consumer load groups and price structures

Network Tasman classifies connections into load groups primarily according to capacity requirements. Connections are grouped in this way because network costs are largely driven by peak demand. Capacity requirements represent the theoretical maximum load of each connection during the network peak. Although few connections use the full capacity of their connection, capacity represents a reasonable proxy for grouping connections that have similar peak demand and therefore impose similar costs on Network Tasman.

Group 0: Unmetered connections

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

- **0UNM (Low Capacity supplies)** is for low-capacity connections fitted with a small fuse with very low consumption. They are intended for connections such as phone boxes, roadside communication cabinets, electric fences, etc. The price is a fixed charge per day.
- **0STL (Streetlights)** is used for general street lighting and is also used for unmetered streetlights that are 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

Most residential consumers and some small businesses (i.e. those with a maximum delivery capacity of 15kVA) are Group 1 connections. Group 1 connections fall into three price categories:

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

All three Group 1 price categories have the same choice of 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 option is new for the 2023/24 pricing year. The purpose of this new tariff is to better signal the cost of using the network at different times of the day. Further discussion on the design of this tariff can be found in Section 4.

From 1 April 2023, the Peak/Off-peak tariff will become the default tariff for most Group 1 consumers with an uncontrolled supply. All Group 1 consumers on the Anytime tariff with a communicating AMI meter will be moved to the Peak/Off-peak tariff on 1 April 2023.

Consumers on the Day/Night tariff will be unaffected by this change. However, consideration will be given in the future to simplifying Network Tasman's tariff options by consolidating the Day/Night and Peak/Off-peak tariffs.

Additionally, the Anytime and Day/Night tariffs will be closed to all new connections, except when the new connection does not have a communicating AMI meter. Where this occurs, the consumer will be allocated to the Anytime tariff.

Controlled Prices

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

- **Controlled water** – where Network Tasman may control the consumer's hot water supply (within specified service levels).
- **Night only** – supply under this option is limited to 11pm and 7am. 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 2 connections benefit from the controlled hot water price, which is less than half of the standard uncontrolled price. A further 7% of connections use the Night only option.

Group 2: Metered connections 20-150kVA

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

The Group 2 capacity price is expressed as "dollars per kVA" and is based on the connection's installed fuse capacity (between 20 and 150 kVA).

Group 2 connections have the same tariff options described for Group 1 consumers above.

Group 3: Metered connections of 150kVA or more

Group 3 consumers have capacity requirements of at least 150kVA. Group 3 contains larger business consumers. Group 3 connections are subject to demand charges measured in kVA based on the single highest half hour of Anytime Maximum Demand (AMD) during the previous 12-month calendar period.

The remaining revenue is collected using a seasonal time-of-use (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 over 3MVA. Group 6 consumers have fully fixed charges that reflect high levels of asset dedication. These consumers pay an annual fixed rental irrespective of their load profiles.

2.2. Network Tasman prices from 1 April 2023

Network Tasman reviews its line prices annually, with new pricing taking effect from 1 April each year. The price schedule for 2023/24 is set out in Appendix C.

Charges for new loads can be found in our new load policy on our website.

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 2023, Network Tasman has forecast an average increase in pre-discount distribution prices of approximately 4.7%).

This increase is primarily to account for two factors:

- Inflation and the increasing cost of investing in, and operating, our business; and
- The new requirement to pass settlement residue payments received from Transpower on to retailers and directly billed consumers.

These two factors each contribute to broadly half of the increase in distribution revenues required.

The current high inflation environment has broadly affected the costs of operating our business, resulting in cost increases across the business.

Historically, Network Tasman has retained settlement residue payments received from Transpower. The receipt of these payments had the effect of reducing the revenues Network Tasman needed to recover from consumers via lines charges.

Following a recent Code amendment by the Electricity Authority, distributors must pass settlement residue payments directly through to their customers (generally retailers).

Network Tasman has increased lines charges to account for the loss of this revenue.

Pass-through price component

The portion of prices associated with pass-through costs has increased by 5.6%. Pass-through costs account for a small percentage (≈1%) of overall lines charges.

Transmission price component

The transmission price component has primarily recovered the cost of using the national transmission grid, which is owned and operated by Transpower and regulated avoided cost of transmission payments.

Network Tasman has forecast transmission costs to fall by $1.9m for the 2023/24 year. This reduction is primarily due to the Electricity Authority amending the Code to remove the requirement for distributors to make avoided cost of transmission payments.

Price level changes for individual load groups

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

Groups 0, 1 and 2

From 1 April 2023, groups 0, 1, and 2 will experience the following changes:

- **Group 0** - overall prices for Group 0 decrease on average by 4%
- **Group 1** - on average, prices for Group 1 increase by 0.5%.
- **Group 2** - prices for Group 2 are forecast to increase by 4.6% on average.

The increase for Group 2 is primarily the result of the new methodology for allocating transmission charges across the consumer groups, increasing the proportion of transmission costs to be recovered from Group 2 connections.

Group 3

On average, Group 3 connections are forecast to experience a 1% reduction in their lines charges.

Group 6

On average, Group 6 connections will experience an overall price decrease of 15%.

2.3. Consumer Impact

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

For comparative purposes, this analysis assumes the hypothetical consumer uses the same volume of electricity in 2023/24 as in 2022/23. In practice, consumption varies from year to year, so the actual effect on individual consumers will also be influenced by the year-on-year variation in consumption.

Group 1 residential consumers using less than 8,000kWh/year will experience an increase in their overall lines charges. This is primarily because the effect of the 15c/day increase in the fixed charge for consumers on the regulated low fixed charge tariff outweighs the benefit these consumers enjoy from lower consumption charges.

Of the residential consumers that experience higher lines charges, the significant majority (more than 94 per cent) of those consumers will see their lines charges increase by less than 64c/week. The theoretical maximum a consumer's lines charges can increase is $1.05/week. However, this is for a consumer that maintains an active connection to our network but does not consume a single kWh of electricity during the entire year.

Two countervailing factors drive the change in prices for Group 1 consumers. A higher distribution revenue requirement has pushed prices up, and lower transmission costs have mitigated the increase in distribution revenues. The reduction in transmission revenues offsets approximately 70% of the increase in distribution revenues.

Table 1 below summarises the effect Network Tasman's pre-discount price changes are expected to have 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 distribution charge	Change in transmission charge	Change in total lines charges ($)	Change in total lines charges (%)
0	$44.03	$10.87	$54.90	50.0%
1,000	$41.71	$6.07	$47.77	25.8%
2,000	$39.39	$1.26	$40.65	15.6%
3,000	$37.07	-$3.54	$33.52	9.9%
4,000	$34.75	-$8.35	$26.40	6.4%
5,000	$32.42	-$13.15	$19.27	3.9%
6,000	$30.10	-$17.96	$12.15	2.2%
7,000	$27.78	-$22.76	$5.02	0.8%
8,000	$25.46	-$27.57	-$2.11	-0.3%
9,000	$23.13	-$34.15	-$11.03	-1.4%
10,000	$24.27	-$38.96	-$14.69	-1.8%
11,000	$25.42	-$43.78	-$18.36	-2.1%
12,000	$26.56	-$48.59	-$22.02	-2.5%
13,000	$27.71	-$53.40	-$25.69	-2.7%

Group 2 charges vary by the capacity and consumption of each connection. As Group 2 covers a wide array of capacity bands (20kVA to 150kVA), there are many capacity/consumption combinations across Group 2. For simplicity, the impact assessment is presented below in Table 2 for consumers with a 40kVA connection, a common capacity for Group 2 connections. As prices are the same for all Group 2 consumers, the table below indicates the relative effects across Group 2 consumers.

As most of the price change for Group 2 has been recovered via an increase to the fixed charge portion, the dollar effect of the price increase is reasonably uniform across the consumption bands for a given connection capacity.

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

Total kWh/pa	Change in distribution charge ($)	Change in transmission charge ($)	Change in total lines charge ($)	Change in total lines charge (%)
0	$39.53	$99.55	$139.08	10.0%
5,000	$40.79	$98.58	$139.37	8.4%
10,000	$42.06	$97.61	$139.66	7.2%
15,000	$43.32	$96.64	$139.96	6.3%
20,000	$44.59	$95.66	$140.25	5.6%
25,000	$45.85	$94.69	$140.54	5.1%
30,000	$47.12	$93.72	$140.83	4.6%
35,000	$48.38	$92.75	$141.13	4.2%
40,000	$49.64	$91.77	$141.42	3.9%
45,000	$50.91	$90.80	$141.71	3.6%

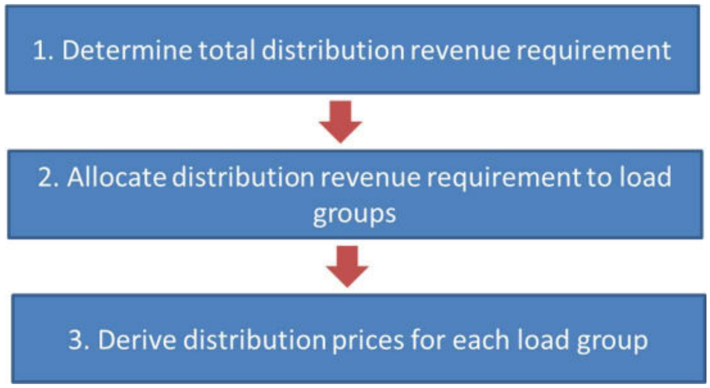
50,000	$52.17	$89.83	$142.00	3.4%
55,000	$53.44	$88.86	$142.30	3.2%
60,000	$54.70	$87.89	$142.59	3.0%
65,000	$55.97	$86.91	$142.88	2.9%
70,000	$57.23	$85.94	$143.17	2.7%
75,000	$58.50	$84.97	$143.47	2.6%
80,000	$59.76	$84.00	$143.76	2.5%

For Group 3 connections, higher distribution charges have, on average, been offset by reduced transmission charges. The net effect of these two factors is slightly lower overall prices as the transmission effect marginally outweighs the increase in distribution charges.

Lower transmission charges to Group 3 result from Network Tasman incurring lower transmission charges overall and Network Tasman's new methodology for allocating transmission charges across consumer groups allocating a lower proportion of those costs to Group 3. The effect of these changes on individual Group 3 connections will be influenced by their network use.

3. Core Methodology

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



As price setting is an iterative process that takes account of factors like bill impacts and regulatory obligations, there can be a feedback loop between the steps outlined above.

This section focuses on the first two steps outlined above.

Network Tasman is subject to the Commerce Commission's Default Price-Quality Path, which applies a revenue cap limiting the revenue that Network Tasman can recover in each financial year. Network Tasman's forecast total allowable revenue for the 2023/24 year is $43.6m.

As a consumer-owned distributor, Network Tasman's focus is to be a successful business that operates a safe and reliable network at the lowest cost to consumers. Although Network Tasman is subject to revenue cap regulation, the business has not needed to recover the full value of the revenue cap to achieve these outcomes. Accordingly, the target revenue is determined by the business's current and forward-looking operational needs rather than the allowable revenue afforded under the Commerce Commission's Price-Quality regulation.

Network Tasman's total post-discount revenue requirement for 2023/24 is $40.2m. This compares with the total revenue requirement in 2022/23 of $39.6m.

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, 2023/24

Cost component	Cost ($m)
Indirect Opex	$3.4
Direct Opex	$12.1
Depreciation	$7.4
Return on Capital	$5.0
Transmission and pass-through	$12.4
Total Revenue Requirement	**$40.2**

The information used to determine the value of these cost components is drawn from a range of 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 is shared across many consumers. Network Tasman uses a range of allocators to apportion costs across consumer groups. These allocators are chosen to select key underlying drivers of each cost component, so they are allocated to the groups that most contributed to that driver. The application and choice of cost allocators inevitably involve judgement 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 is used to inform decisions around the target revenue required from each consumer group.

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

Direct opex and depreciation

Direct network opex and depreciation 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; and
- Dedicated networks.

The following table identifies which network segments are used by each load group.

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

A measure of cumulative capacity is used to allocate the costs associated with distribution transformers across load groups. The allocation of other network costs to each load group is informed by estimates of each load group's contribution to coincident maximum demand (CMD). CMD is used because network direct investment and costs are largely a function of peak period demand.

Network Tasman has refined the CMD measure used to allocate costs to consumer groups and has adopted a more comprehensive dataset to calculate the contributions from Groups 0, 1 and 2 to the peak demands based on three years of half-hourly wholesale market data. The refined CMD measure rebalances allocations between consumer groups, the effects of which have been introduced incrementally to manage bill impacts.

No lower network costs are attributed to load Group 6, CB or MAT, as these groups rely solely on upper network assets for their supply. Allocations for the 400V cost components are modified to reflect Group 3's lesser reliance on these assets.

Indirect opex

Indirect network costs include general administration, overhead costs and depreciation on 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 & 3 in proportion to their relative shares of installed capacity (measured by fuse size or dedicated transformer capacity). Allocation of indirect costs is more arbitrary than for direct costs. However, an allocator based on installed fuse capacity provides a reasonable balance between allocating by customer numbers and allocating by some measure of demand.

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, revenue requirements are set on the basis of the business's 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 a number of periods to smooth the effect of the change on consumer groups.

Transmission charges

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

- Connection charge
- Benefits-based charge
- Residual charge
- Transpower Works Agreements

The costs of the first three components are derived according to the Transmission Pricing Methodology (TPM) regulated by the Electricity Authority. Transpower Works Agreements are bilateral agreements with Transpower for the provision of dedicated connection assets and are subject to commercial negotiation.

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

With the introduction of the new TPM, Network Tasman has had to derive a new methodology for allocating the new benefits-based, residual and transitional charges across consumer groups.

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 new 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 (investments valued at more than $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.

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 assessment period (2014 to 2018) by multiplying the difference between the actual spot price during each trading period and the estimated spot prices that would have occurred had the investment in question not been made, by each transmission customer's load during each trading period.

This calculation is undertaken for each trading period between the 2014 and 2018 assessment period. The sum of which is the net private benefit for that load. The cost of an investment is allocated across transmission customers in proportion to their relative net private benefit.

It is impractical for Network Tasman to replicate this calculation for each consumer group - there are more than 70,000 trading periods in the four-year assessment period. Instead, Network Tasman has used each consumer group's relative aggregate load figures (MWh) for the entire four-year assessment period to allocate Appendix A charges.

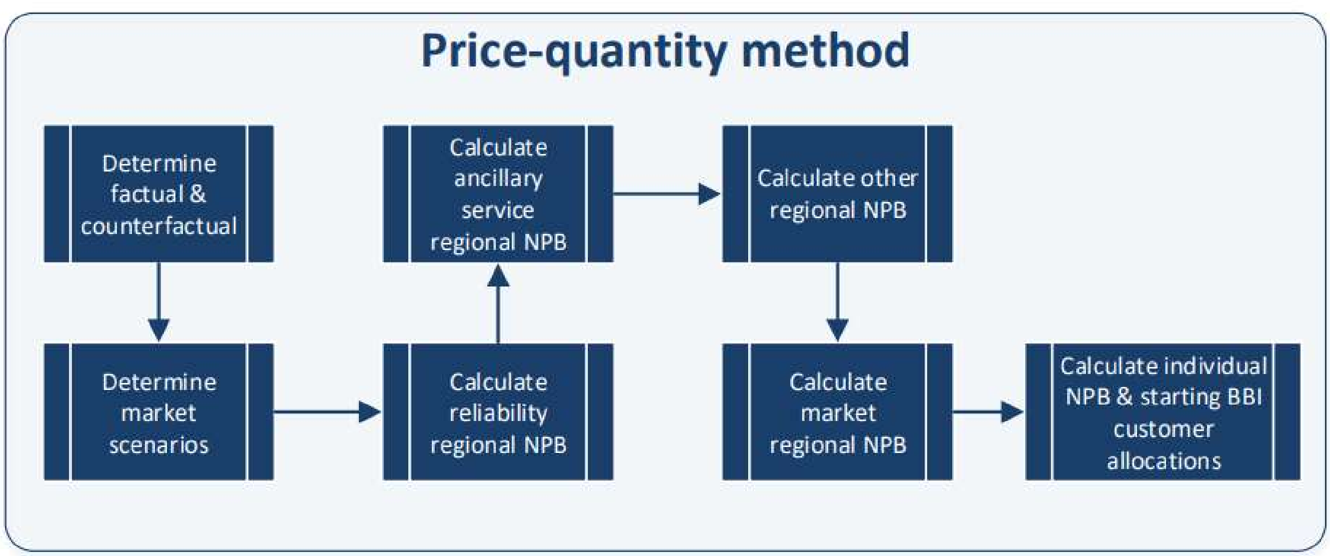
For the Simple method, Transpower derives regional net private benefits for each modelled region, then calculates a simple method factor for each member of a regional customer group. Starting allocations are based on the product of a customer's simple method factor and the net private benefit for their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

A customer's simple method factor is its share of historic injection or offtake in the relevant region between 2018 and 2021. Accordingly, Network Tasman has allocated the costs of simple method benefits-based charges to consumer groups based on their offtake between 2018 and 2021.

The Standard method is an umbrella term covering a number of different methodologies. For the 2023/24 pricing year, the Standard method allocates the costs of just one project, the Clutha Upper Waitaki Lines Project (CUWLP).

The methodology used to allocate Standard method benefits-based charges is more detailed and complex than the Appendix A and Simple methods. Transpower summarises the methodology used to allocate the CUWLP project costs with the diagram below.



It is not possible or desirable for Network Tasman to replicate most of the steps in this methodology. Many of the calculations are made by Transpower using proprietary software that transmission customers are unable to view.

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 based on each customer's offtake or injection (kWh) between 2014 and 2019.

Accordingly, Network Tasman has allocated its Standard method benefits-based charges to consumer groups in proportion to their relative kWh load between 2014 and 2019.

Residual charges are allocated to Transmission customers based on 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 did not routinely record half-hourly demand data for Groups 0, 1 or 2 between 2014 and 2019. 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 of these consumer groups at the relevant periods.

As Network Tasman has internal records of, or has access to, the relevant data for each consumer group to allocate residual charges to each consumer group in proportion to their contribution to Network Tasman's residual charge, Network Tasman has allocated residual charges to consumer groups using the same parameters Transpower has used to allocate the 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.

Historically, transmission charges have also included the cost of making regulated avoided cost of transmission charge payments to qualifying generators. However, recent changes to the Code have resulted in Network Tasman no longer being able to make regulated avoided cost of transmission charge payments to generators from 1 April 2023.

Revenue requirement by load group

Several factors are considered 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)[4]

Consumer Group	Revenue requirement
Group 0	0.2
Group 1	18.0
Group 2	8.5
Group 3	7.9
Group 6	1.8
CB	1.8
MAT	0.0
NEL	1.6
Sundry	0.5
Total	**40.2**

[4] Some of the total values may not match the sum of the figures presented in the table due to rounding.

4. Determining prices

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

4.1. Price setting for each consumer group

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); and
- 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 profile where known 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 by each price component Network Tasman uses judgement to balance the conflicting demands, including:

- impact on consumers
- economic rationale
- government policy and regulatory requirements
- the expectations of different electricity consumers

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

Groups 1 and 2

Consumers in Groups 1 and 2 are subject to the same tariff options. Accordingly, prices across the two groups are set in a similar manner.

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 45c/day to comply with regulatory requirements. The two remaining price categories have a fixed charge of $1.06/day.

Sixty-two per cent of the total revenue collected from Group 1 connections for the 2023/24 pricing year is forecast to be recovered via fixed daily charges. If the 1RL price category is excluded, this figure increases to 76%. For transmission charges, these figures are 51% and 64%, respectively.

In response to the Electricity Authority's expectation that distributors increase the proportion of transmission revenues recovered via fixed charges, Network Tasman has significantly increased the proportion of transmission revenues recovered via fixed charges for the 2023/24 pricing year. The LFC regulations limit the extent to which this can be achieved by placing a ceiling on the fixed charge that can be recovered from these consumers. For non-LFC Group 1 consumers, the proportion of transmission revenues recovered via fixed charges has increased from 46% to 64%.

Network Tasman has limited the year-to-year changes in fixed charges to manage bill impact. However, we expect to continue increasing the fixed proportion of transmission charges, as bill impacts allow until all Group 1 transmission charges are recovered via a fixed charge.

For Group 2, fixed charges were raised slightly to increase the forecast revenue from fixed charges from 63% to 65%.

The residual revenues required from each group after fixed charges have been accounted for are recovered via consumption prices.

A set of relative weightings is applied to the consumption prices on offer. For longstanding tariff options, the relative weights have been partly driven by legacy issues but also take account of the relative costs of providing network services at peak versus off-peak times and the benefits to the network of having interruptible loads.

These weightings provide a signal for consumers to:

- shift consumption from peak to night periods and
- permit components of their supply to be interrupted by Network Tasman load control devices.

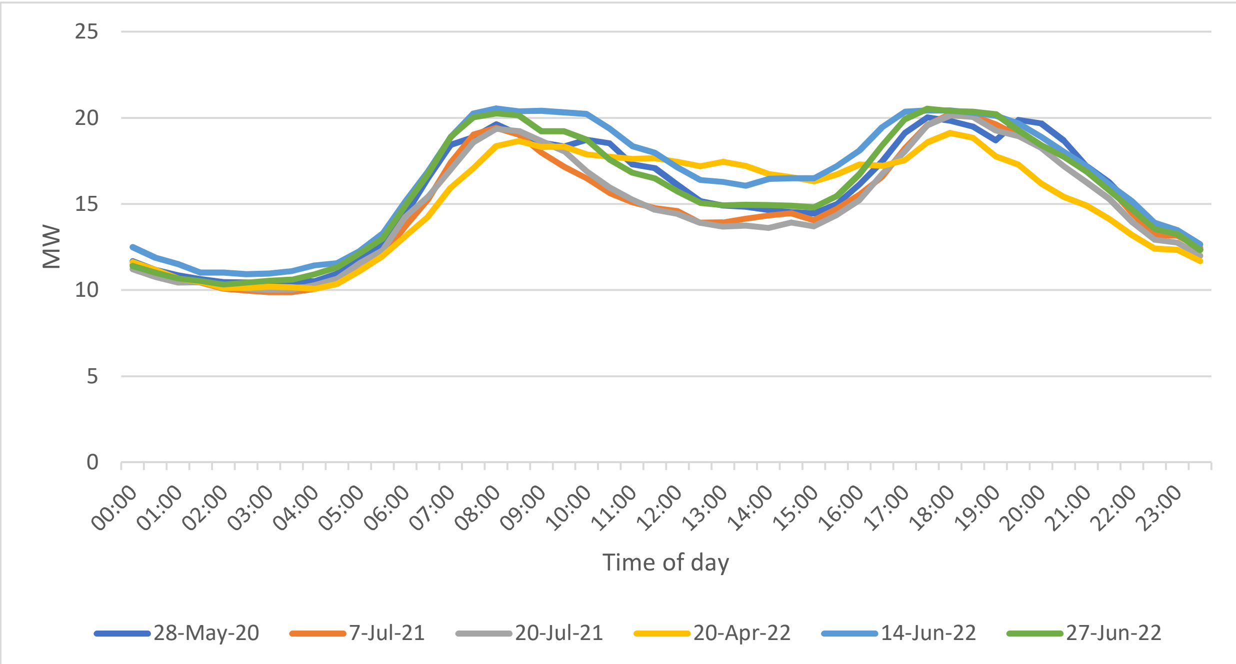
Network Tasman has introduced a new Peak/Off-peak tariff option for Group 1 and 2 consumers for the 2023/24 pricing year.

The design of this tariff was informed by the timing and duration of our network peaks. This is because we want to encourage consumers to shift discretionary demand, such as EV charging, dishwashers, washing machines, etc away from the peak periods and into the off-peak periods.

The traditional network load profile exhibits morning and evening peaks with a small trough in demand during the middle of the day and a large trough in demand overnight. Generally, the Network Tasman load follows this profile.

The figure below illustrates the network load at the Motueka zone substation on typical autumn/winter days over the past two years. The Motueka zone substation has a firm capacity of 20.5MW.

FIGURE 1: MOTUEKA ZONE SUBSTATION LOAD PROFILE

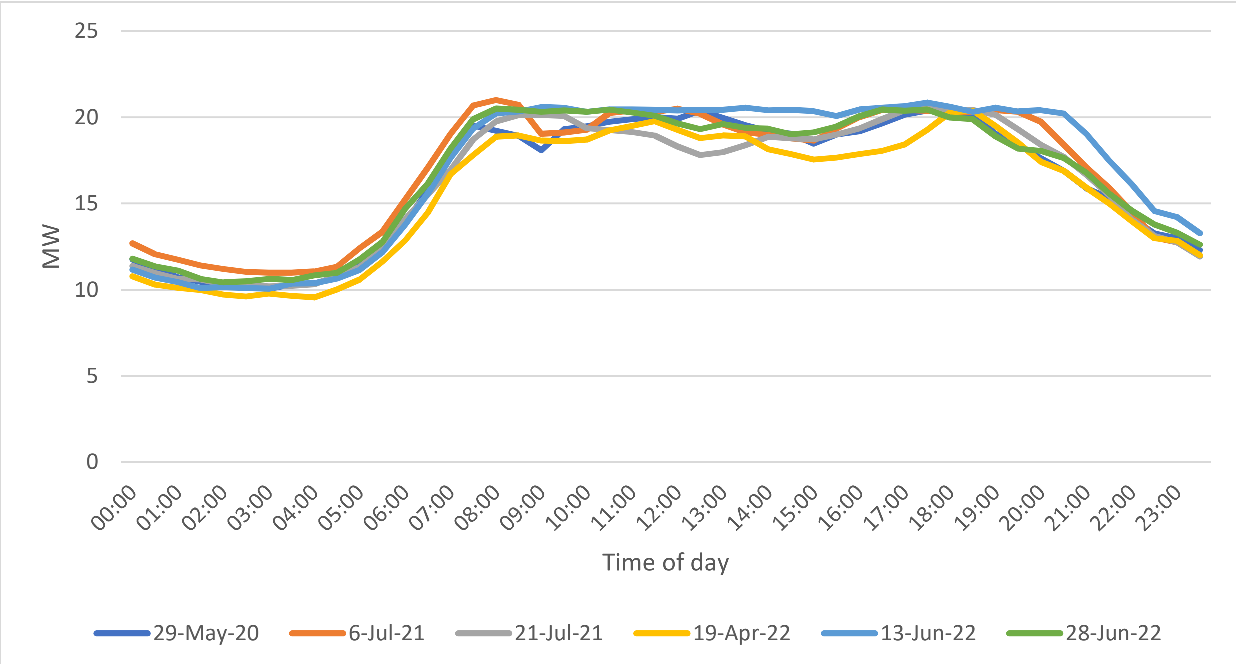


The Motueka zone substation is used for this analysis because it is currently subject to a capacity constraint (it is currently undergoing a capacity upgrade) and provides a valuable case study of the load profile that can be expected in an area facing a capacity constraint. The Motueka zone substation also serves as a good case study because its load profile broadly mirrors the network load profile as a whole.

When designing this tariff, Network Tasman focused on what the network load will be on the days of peak network load (not the average), when the network is reaching its capacity limits and load-shifting capabilities are at, or near, full utilisation. It is the load at these times that triggers network investment. How consumers use the network on these days is the key driver of the timing of these network investments, so we have designed the tariff to encourage consumers to behave in a manner that assists Network Tasman to efficiently manage network load at these times.

The figure below illustrates the load profile of the six days of highest load on the Motueka zone substation over the past two years to July 2022.

FIGURE 2: 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 2. These loads are then restored after the underlying peak has passed. The effect of this action is to shave load off the top of the morning and evening peaks and move 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.

Although the network load in Figure 2 above begins to peak from 7:30am until as late as 9pm, Network Tasman has configured the peak period to apply from 7am until 11pm.

There are two reasons for extending the window further into the evening. Firstly, in extreme circumstances, Network Tasman has needed to control load beyond 9pm. Extending the peak period until 11pm provides Network Tasman with the capability to manage load during periods of significantly heightened demand.

The second reason for ending the peak period at 11pm is because we expect EV charging, in particular, to be a load type that will respond to our price signals. As the number of EVs on our network grows, we expect to see network load rise at 11pm, potentially to the point that we see a secondary network peak at 11pm. Ending the peak period at 11pm provides the network with significantly more capacity to accommodate the expected growth in EV charging demand than would be available if the peak period ended at 9pm or 10pm.

Notwithstanding these factors, Network Tasman will monitor network use and consider reviewing these time periods as consumer response to this tariff becomes clearer.

Weekends have been classified as off-peak because weekend peak load isn't of the same magnitude as that exhibited during weekdays.

Network Tasman has initially introduced a moderate price differential between the peak and off-peak prices. The reason for this was to manage the initial bill impacts of the change. Network Tasman anticipates increasing the differential gradually to provide consumers with better signals about the costs of using the network during peak periods.

For the 2023/24 pricing year, the Peak/Off-peak tariff has been designed to be cost neutral for the average consumer when compared to the Anytime tariff it is replacing.

Group 3

Prices for Group 3 connections have been amended from 1 April 2023 to reflect the changes to the transmission pricing methodology (TPM).

Historically, Network Tasman has passed through Transpower's regional coincident peak demand (RCPD) charge through to Group 3 connections in proportion to their contribution to Network Tasman's charge. Network Tasman also recovered a small proportion of distribution revenues using this charge.

Network Tasman has a full review of Group 3 prices scheduled for 2023/24. However, changes to the TPM required a change to Group 3 prices in advance of is full review.

The new TPM will be introduced on 1 April 2023. In the new TPM, the connection charge remains largely unchanged. However, the RCPD charge is being replaced with two new charges: a benefits-based charge and a residual charge.

The benefits-based charge allocates the cost of each new Transpower investment to customers in proportion to the (estimated) benefits they will receive from each investment. All remaining costs (i.e. those not recovered via the connection and benefits-based charges) are recovered via the residual charge.

The benefits-based and residual charges are both designed to be fixed-like charges. That is, Network Tasman's allocation of benefits-based and residual charges will not be influenced by how we use the transmission network.

With the RCPD charge being removed from Transpower prices next year and replaced with the benefits-based and residual charges, the RCPD component in our Group 3 prices becomes redundant and must be removed or replaced.

The Electricity Authority has taken a keen interest in how distributors pass on the new TPM prices to end consumers and appears to be highly motivated to ensure distributors use efficient prices to recover transmission charges.

In late 2022, the Authority published an update to its distribution pricing practice note in which it stated the new transmission charges have been designed to be fixed (or fixed-like). The Authority stated the most efficient way to recover transmission costs is via charges designed to have limited influence on usage decisions, i.e. fixed charges.

It is inefficient for transmission costs to be recovered via variable charges because they encourage consumers to change their electricity consumption at specific times despite these changes having minimal impact on Network Tasman's transmission charges.

The Authority's guidance was issued during the second half of Network Tasman's project to remove the RCPD charge from Group 3 prices. Accordingly, Network Tasman's ability to take account of this information was limited for the 2023/24 pricing year.

Nevertheless, at a high-level Network Tasman considered four options to satisfy the Authority's concerns. These options included:

- Bringing the full review for Group 3 prices forward to be completed prior to 1 April 2023.
- Using an anytime maximum demand (AMD) charge to recover all Group 3 transmission costs (an AMD charge is already used to recover connection costs).
- Replacing the existing RCPD charge with a daily fixed charge.
- Replacing the existing RCPD charge with a capacity charge.

Of the four options, Network Tasman opted to use an AMD charge to recover all Group 3 transmission costs.

Network Tasman elected not to bring forward the full review of Group 3 prices. Network Tasman's pricing reform roadmap already had a review of Group 1 and 2 prices scheduled for 2022/23 and intentionally staggered the review of Group 3 prices to ensure appropriate resources were available for the review.

A fixed daily charge was not selected for equity reasons.

The introduction of a capacity change was not selected because, from an efficiency perspective, it doesn't appear to offer a clearly superior outcome to an AMD charge.

Daily fixed charge

The efficient way to recover a fixed input cost is to recover it via a charge that minimises the incentives for consumers to alter their behaviour.

A daily fixed charge, is a charge that is imposed on all consumers, irrespective of their characteristics, where all consumers are charged the same amount.

When applied in its purest form, the charge does not vary according to consumer characteristics (capacity, location, etc.) and all incentives for these consumers to alter these characteristics are removed, assuming the fixed charge does not affect a consumer's decision to connect (or remain connected) to the network in the first place. In an economic sense, this is a highly efficient way to recover fixed costs.

Although it is efficient to charge all consumers the same daily fixed charge, there are clearly material equity issues. The Authority implicitly acknowledged this as an issue in its guidance on how distributors should pass transmission charges through to consumers. Specifically, the Authority endorsed using anytime maximum demand charges to allocate the residual charge to consumers because:[5]

> "an allocation based on maximum demand could reflect the relative size of each customer's maximum usage of the network. Any metric referencing size or use would ideally be a historical reading of the metric, as this would create fewer possibilities for avoidance, making it a less distortionary allocator."

The Authority implicitly acknowledges that allocating fixed costs to consumers in proportion to their relative size is a desirable outcome, presumably because ignoring relative size would result in considerable equity issues.

Even if the strict application of the charge is relaxed so it is differentiated by consumer group, equity issues remain.

There is significant variation in the size of Group 3 consumers. For example, the smallest consumer in Group 3 has a maximum (notional) demand of 150kVA. Under a fixed daily charge framework, this consumer would incur the same daily fixed charge as the largest consumer who is more than ten times larger, with an AMD of more than 2,000kVA.

These equity issues could be mitigated by creating a tiered charge based on the consumer's connection capacity. Although doing so effectively turns the daily fixed charge into a capacity charge (which is considered later).

Replace the RCPD charge with a capacity charge

A capacity charge was not selected because it does not offer a clearly superior option to an AMD charge when considered on an efficiency basis.

An AMD charge does provide incentives for consumers to alter their behaviour. A consumer can lower their charges if they are able to reduce their consumption during their period of maximum demand. Any reduction in a consumer's anytime maximum demand will flow through to lower lines charges for the following year. If the operational cost incurred by a consumer to reduce their peak demand is less than the savings they would enjoy from a lower anytime maximum demand charge, the consumer has incentives to do so.

The strength of this incentive is the uniform, irrespective of consumer size.

However, capacity charges also provide incentives for consumers to alter their behaviour. In some cases, these incentives can be very strong, particularly for consumers that find themselves at the boundaries of their nominated connection capacity.

For example, in the event connection capacities are available in 100kVA increments, a consumer with a maximum demand of 205kVA would select a fuse capacity of 300kVA. This consumer could move down from the 300kVA capacity band to the 200kVA capacity band by reducing their maximum demand by

[5] Electricity Authority, Distribution Pricing: Practice Note, Second Edition v2.2, October 2022, p. 20, para 117.

6kVA. In this circumstance, a 3% reduction in AMD would result in a 50% reduction in their capacity charge.

Similar behavioural incentives occur for consumers sitting near the top of their capacity band to limit their load growth.

The decision about whether a capacity charge or an AMD charge is a more efficient methodology for recovering transmission costs depends on an interpretation of whether the stronger incentives that capacity charges create for a subset of consumers to change their behaviour results in more overall behaviour change than the smaller but uniform incentives created by the AMD charge. It is not immediately clear that one is superior to the other.

Given Network Tasman will conduct a full review of Group 3 prices in 2023/24 and the circumstances outlined above, Network Tasman has elected to limit changes to Group 3 prices to those necessary to address the immediate issue prompted by the new TPM.

Network Tasman already uses an AMD charge to recover the connection portion of transmission costs, so there are minimal additional costs to recovering the remaining components of the Group 3 transmission costs via an AMD charge.

Network Tasman does not consider there to be material benefits from undertaking a piecemeal change to Group 3 prices ahead of the full review of these prices in 2023/24. As part of this forthcoming review, Network Tasman will further consider the issues discussed above and will seek a broad range of stakeholder views, including the Electricity Authority.

Accordingly, Network Tasman has chosen to recover all Group 3 transmission charges via an AMD charge. No change has been made to the existing seasonal time-of-use (kWh) charge.

The move to recover all Group 3 transmission costs via an AMD charge will have a material impact on the lines charges paid by some Group 3 consumers. Summer peaking load has traditionally incurred relatively low transmission (RCPD) charges as Upper South Island transmission peaks have primarily occurred during winter.

Recovering all Group 3 transmission costs via an AMD charge will result in summer peaking loads incurring relatively higher transmission charges and winter peaking loads incurring lower transmission charges (everything else being equal).

To mitigate against the bill impact of this change, Network Tasman has capped the year-on-year increase in transmission charges a Group 3 connection can experience at 20%. For the average Group 3 connection, a 20% increase in transmission charges would translate to an overall increase in lines charges of approximately 5%.

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.

Large generators

Network Tasman has two large embedded generators. One generator connected in 2021 and the other was acquired as an embedded generator when Network Tasman purchased Transpower's 66kV assets between Stoke and Golden Bay. The distribution charges applicable to the acquired embedded generator are specified within the connection contract.

Charges for the new generator are 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 $5.3m

Network Tasman does not have set criteria for when a non-standard contract should be used or how prices should be set in the event a non-standard contract is used.

Non-standard contracts are typically used in circumstances where a consumer requires a connection with a high level of asset dedication and/or a service that is not available under the standard price categories.

Non-standard contracts and prices are typically applied to, and based on, large connections with high levels of asset dedication. Prices for connections with a non-standard contract are generally set after giving consideration to the assets involved and any additional charges from Transpower.

Distribution charges for non-standard contracts are typically 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.

In the event of a loss of supply, Network Tasman's obligations and responsibilities to consumers with non-standard contracts are no different to those for consumers with standard contracts.

6. Distributed generation (DG)

Network Tasman uses the regulated terms as 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 six hydro plants connected to the HV network.

Pricing for four of the hydro plants connected to the HV network is specified in the individual connection agreement with each generator. Pricing for the remaining two generators is set with reference 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.

For DG connecting to the HV network, the charges outlined below are calculated on an annual basis and invoiced in arrears in equal monthly instalments across the pricing year (April-March).

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

- Distribution costs – The cost of deploying new distribution assets in order 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 as a result of DG connecting to our network, including regulatory charges such as Electricity Authority Levies.

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. 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.

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

6.2. Distributed Generation Lines Charge

The DG lines charge recovers costs associated with 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 and exceed the capacity required for the local network.

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 regulated 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 (currently 4.57%). Accordingly, the calculation will be:

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

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.

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, where multiple DG is involved, 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 they are recorded in Network Tasman's RAB or equivalent. An annual depreciation charge will be calculated based on the standard physical asset lives for each appropriate asset class. 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, a 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.

Accordingly, maintenance costs can vary significantly, making it difficult to prescribe a precise methodology for allocating maintenance costs. Rather, the methodology for recovering maintenance costs will be set on a case-by-case basis.

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 a new DG proposes to connect to assets that Network Tasman has provided exclusively for conveying electricity produced by other DG owners, 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 transmission of the new or increased generation and maintain the transmission capability 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 for any change in the asset values that underpin the connection charge. These changes may have occurred as a result of asset renewals, revaluations and replacements.

6.3. Transmission-Related Transactions

Network Tasman will directly pass through the cost of any incremental cost it incurs from Transpower as a result of connecting DG to its network. The following section describes the most common incremental cost components Network Tasman incurs as a result of DG connecting to its network.

Recovery of Connection Charges

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

These costs generally arise via a direct increase in connection charges due to the installation of new assets or 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 as a result of a bilateral agreement between Network Tasman and Transpower 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 any DG. Given the complexity of calculating benefits-based charges, the materiality and practicality of determining a DG's contribution to Network Tasman's benefits-based charges will be taken into consideration 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 standards. 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 it incurs as a result of any subsequent breach investigation from the relevant DG owner/s.

6.6. 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.

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

In what follows each Distribution Pricing Principle is identified and Network Tasman's general compliance with the principle is discussed.

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 which at its limit requires a separate test for each of Network Tasman's ICPs. To accurately estimate both incremental costs and standalone costs for particular customers or groups of customers is difficult and resource intensive so the matter is addressed in general terms below.

As a general principle, if line prices are cost-reflective and costs are below bypass levels the subsidy-free test will be met.

Allocation of consumers and costs to load groups and the development of prices for those load groups necessarily involves averaging and a number of assumptions. The resulting price is at best reasonably cost-reflective for broad groups of consumers.

However, the subsidy-free range for line services for mass market consumers is also likely to be broad because incremental costs for the additional consumer/kVA/kWh are low while their standalone costs of supply are very high. This broad range means the pricing methodology described in this document will result in prices within the subsidy-free range.

Standalone Test

Distribution networks are natural monopolies and by definition deliver significant and long-term economies of scale to the extent that tests for standalone costs of alternative lines supply (overbuild) against existing cost-reflective prices for mass market consumers should be largely redundant.

It is likely that Network Tasman's line prices for Group 1 & 2 consumers are materially lower than the standalone economic costs associated with alternative lines supply. This contention is supported by the fact that:

- Network Tasman's pricing methodology is cost-reflective by Load Group.
- Transpower directly charges distributors for their connection assets at GXPs. There are very strong economies of scale with respect to grid connection.
- New overbuild costs and Network Tasman's line business' economies of scale means any replication of Network Tasman distribution assets would be uneconomic when assessed against

Network Tasman's current mass market line charges, either for individual consumers or for larger groups of consumers.

An alternative standalone test for small and medium-sized consumers is to compare the cost of line supply against the costs of alternative standalone energy supply using on-site micro-generation plant. At present, the cost of standalone reliance on micro-generation remains higher than the industry average and incremental supply costs, although this test is more about the cost of delivered energy than a disaggregated test focused just on the transport component of electricity costs. With consumers primarily interested only in the overall delivered cost of energy, the standalone subsidy-free test for line charges is problematic given the need to split out line and energy costs.

Standalone cost tests have more relevance for the small number of larger consumers at specific locations on Network Tasman's network. Network Tasman's pricing methodology for Group 3 & 6 consumers is cost-reflective and uses asset-based costs attributable to these customers. Additionally, these consumers share in the economies of scale arising from high levels of sharing of:

- grid exit point costs
- upper network distribution assets
- indirect distribution costs.

Alternative supply via overbuild to these consumers would require economic costs to reflect full asset replacement costs plus the loss of key scale economies. These standalone costs will therefore be well in excess of Network Tasman's current line charges which is not supportive of an overbuild business case.

Network Tasman has previously commissioned bypass costings for major customer sites to identify standalone costs and assess the reasonableness of existing line charge levels. No adjustment to line prices for major customers resulted.

Avoidable Cost Test

Avoidable costs are those costs that can be avoided by supplying one less unit of service.

Examples of avoidable costs could include:

- disconnection of an existing consumer or consumer group (ICP, ICPs);
- supply of one less unit of capacity (kVA, MVA);
- transportation of one less unit of electricity (kWh, MWh);
- billing and customer service costs; and
- additional maintenance costs;

The Authority recognises that distributors run primarily fixed-cost businesses. The implication of running a primarily fixed-cost business is that in most instances incremental changes in the provision of a unit of service (ICP(s)/capacity/consumption) will have a negligible effect on the business's costs.

Incremental cost savings due to a reduction in a unit of capacity, consumption or connections are generally very low for areas where the network has spare capacity. In areas where spare capacity is scarce and new investment is imminent, a reduction in a unit of service may result in a material reduction in costs. However, it is difficult to assign or attribute step changes in core network investment costs to specific units of service unless the change in load (service) is highly customer specific and is large relative to the network segment supporting it and underlying load growth.

At a connection level, Network Tasman's capital contributions policy requires new load to fund the incremental costs of any network extension necessary to support new connections. Network Tasman is generally left with funding new transformer capacity and any augmentation of core network capacity. The result of this is that the combination of capital contributions and line charges is normally sufficient to service Network Tasman's incremental costs for new connections plus provide a proportionate contribution to service and reinforce the core network.

Network Tasman's capital contributions policy also seeks network development levies based on distance and kVA for new loads in uneconomic areas of the network. This helps recover the shortfall in revenue in areas where connection costs tend to be highest. The policy also enables Network Tasman to reserve the right to seek capital contributions from any new load that is large relative to the capacity of the network segment it will rely on. This gives Network Tasman the opportunity to undertake an economic assessment to ensure costs are properly supported by expected future line charge revenues from the large new load. Where there is a shortfall Network Tasman may seek a capital contribution to support the incremental costs.

The implication of Network Tasman's new load policy is that many of the costs derived from incremental changes in supply sit with the party/ies responsible for the change.

Regulatory requirements to offer a low-user tariff option to qualifying consumers tend to compromise incremental cost recovery and create subsidisation of some loads. Network costs for domestic customers do not vary materially with consumption (kWh) levels but the low fixed charge tariff requirements compromise revenue earning ability from low users relative to their costs of supply. This is a material issue as the majority of Network Tasman's domestic customers use less than < 8000 kWh pa.

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 any precision requires, in theory, locational marginal prices, but in practice, this most likely means kVA-based charges that have locational and time components associated with them.

Within an ICP-based pricing regime, the ability to signal the effect additional use has on future investment has been problematic because there has been a desire by stakeholders to avoid differentiated prices across geographical segments of the distribution network for mass market consumers. Many consumers also have an aversion to high capacity and demand-based charges, particularly if it results in significantly higher prices at times when people most want to use electricity.

The alternative for mass market consumers is a set of relatively blunt pricing instruments focused on capacity measured by installed fuse sizes combined with time-of-use kWh tariffs. Network Tasman uses both of these tools in its mass-market prices.

Group 1 capacity/service level signals are relatively muted. However, every Group 1 ICP is restricted to a maximum demand capacity of 15 kVA. Under the LFC regulations, a tariff option must be made available to all residential consumers with a fixed / capacity component of no more than $0.45 per day.

Historically, Network Tasman applied the low user rate across all Group 1 ICPs in order to avoid excessive transaction costs. For the 2019/20 regulatory period, Network Tasman introduced new prices for connections up to 15kVA that are (1) secondary residences (e.g. baches) and primary residences that consume more than 8,000kWh per year, or (2) non-residential consumers.

This change improved the extent to which Network Tasman's prices for 15kVA connections will reflect the available capacity service levels to these consumers, as does the phased removal of the LFC regulations. However, this is limited by the fact that the majority of Network Tasman's residential 15kVA connections use less than 8,000kWh per year and therefore benefit from the LFC tariff. While the LFC remains in place, low use/low load factor consumers under-pay for their available service capacity while high use/high load factor consumers over-pay for the same capacity. This inefficiency is an inevitable consequence of the LFC Regulations.

Network Tasman's Group 2 & 3 line prices feature components directly related to the actual or potential demand consumers in these groups can make on the distribution network and the transmission grid.

Group 3 consumers face an anytime maximum demand charge which in part reflects the current and future cost 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 "additional 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).

The introduction of the mandatory Peak/Off-peak tariff for all Group 1 and 2 consumers with communicating AMI meters will 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.

As noted earlier, Network Tasman applies a kVA per kilometre network development levy regime for new loads locating on high-cost, uneconomic segments of the network. The levy recognises demands for service capacity both 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 has recently introduced a new mechanism into its capital contributions policy (new load policy) that allows flexible loads to share the benefits of deferring investment in distribution assets.

Historically, Network Tasman's new load policy allocated network capacity based on the standard fuse capacity of the connection. This was in recognition that Network Tasman does not have the ability to limit when a connection used the network – load is limited by fuse size only. Similarly, few connections had the ability (or incentives) to manage their load during 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 to these feeders.

The new load policy, as previously drafted, provided little incentive for a flexible load that could avoid the local network peak to connect to the network. This has been amended to allow flexible loads to connect to our network via a *profiled connection*.

A *profiled connection* is available to new connections where network capacity is limited and the new load agrees to a low, or zero, capacity during times of local network peaks, whilst 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 is able to connect to congested parts of the network without triggering costly (and likely prohibitively) expensive 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 price groups, each covering a set connection capacity range. Price Groups are summarised below:

- Group 0 – Low capacity unmetered connections, such as street lights, phone boxes and roadside communication cabinets.
- Group 1 – Metered connections with a capacity of up to 15kVA. This price group accounts for the majority of residential consumers and some small businesses.
- Group 2 – Metered connections with a capacity between 20kVA to 150kVA. This group tends to consist of most businesses and some large residential households.
- Group 3 – Metered connections with a capacity exceeding 150kVA. This group consists of large businesses.
- Group 6 – Individually priced connections with a 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 their use of specific appliances limited 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 the development of the Peak/Off-peak tariff.

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

Network Tasman also offers a 'night only' tariff where the use of specific appliances is limited to operating overnight only (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 are able to minimise or avoid network use during local network peaks. This development allows flexible loads 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 consideration of network alternatives and innovation in the following ways:

- Network Tasman only charges new embedded generators for their incremental costs of connecting to the network. Where warranted, Network Tasman will also consider passing through any avoided distribution costs directly attributable to new embedded generation plant.
- Group 3 prices include a power factor charge that can be levied on consumer sites where the power factor 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 to find ways to avoid increasing peak demands on the network. It also acts as a disincentive for consumers to move up to Group 2 from Group 1, where fixed charges for some consumers are artificially low.
- Network Tasman pricing has, for most consumers, higher kWh rates for on-peak consumption than for off-peak or controlled consumption.
- 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 the 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 the cost of funding a network upgrade.
- Large new loads are subject to an economic test that assesses incremental cost against expected future revenue streams. Where there is a shortfall, a network development levy can be sought. This encourages new loads to minimise their capacity requirements and to consider alternatives. It also encourages new large loads to locate 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 particular chosen localities.

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 recovering any revenue shortfalls, after signalling economic costs, from consumers 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 components 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. Sensitivity to choices concerning shortfall recovery is also likely to be muted. Therefore, the means used to spread and collect any under-recovered costs is only of modest importance.

Demand elasticity is largely a function of the availability of substitutes. In terms of electricity delivered through traditional centralised generation plant, 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 gas for cooking) are not particularly viable substitutes in this region. Commodity prices and the current ban on offshore gas exploration are likely to make them less so in the future.
- 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.

- 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 a number of factors contributing to this outcome, including the large upfront capital costs of solar water heating, ascetics, the practicality of installing equipment on some roof types, renters' inability 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. Network Tasman also needs to retain off-peak, controlled, night and summer kWh tariff rates at substantial discounts to peak and uncontrolled rates for network and demand efficiency reasons.

The use of fixed capacity or daily charges provides the best means of making up for under-recoveries as these cause minimal distortion to consumption patterns at the mass market level. However, until the LFC 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.

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. The TPM has a prudent discount policy. However, unlike transmission customers who are large and whose electricity costs constitute a relatively significant proportion of their operating costs, most distribution consumers do not fit these characteristics.

Most commercial connections operate in 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.

Network Tasman maintains a dialogue with consumers that are of sufficient size to justify the application of a prudent discount. The possibility of a discount remains on the table for these consumers if appropriate.

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 different capacity levels and adopting peak/off-peak 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 adjacent consumers sharing the same network assets, whether they want, or are prepared to pay for the service, or not.

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

Network Tasman has previously surveyed and consulted with Group 3 & 6 and larger Group 2 consumers about price-quality trade-offs in the past as part of the thresholds price control regime. Customer consultation is now undertaken as a biannual survey. The consultations generally show these consumers have primary concerns over the continuity of supply. There appears to be little appetite for any degradation in service quality.

Network Tasman has also canvased electricity retailer views (as representatives of their customers) over line pricing and their primary concerns focus on simplicity and pass-through risk rather than on price/quality trade-offs.

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 for the company from consumers and stakeholders.

The introduction 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 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 strategy

The way electricity is used and generated is continuing to evolve. In this context, Network Tasman considers it important to assess whether there are improvements that can be made to price structures to enable and support consumer choice, while at the same time continuing to provide a sustainable electricity network.

In the context of developing a forward strategy for pricing, Network Tasman has conducted consumer research on price structures and consumer interest in using emerging technologies such as solar panels, battery storage and electric vehicles. The results of that research, as well as an overview of Network Tasman's next steps towards assessing possible price structure enhancements or alternatives, are set out below.

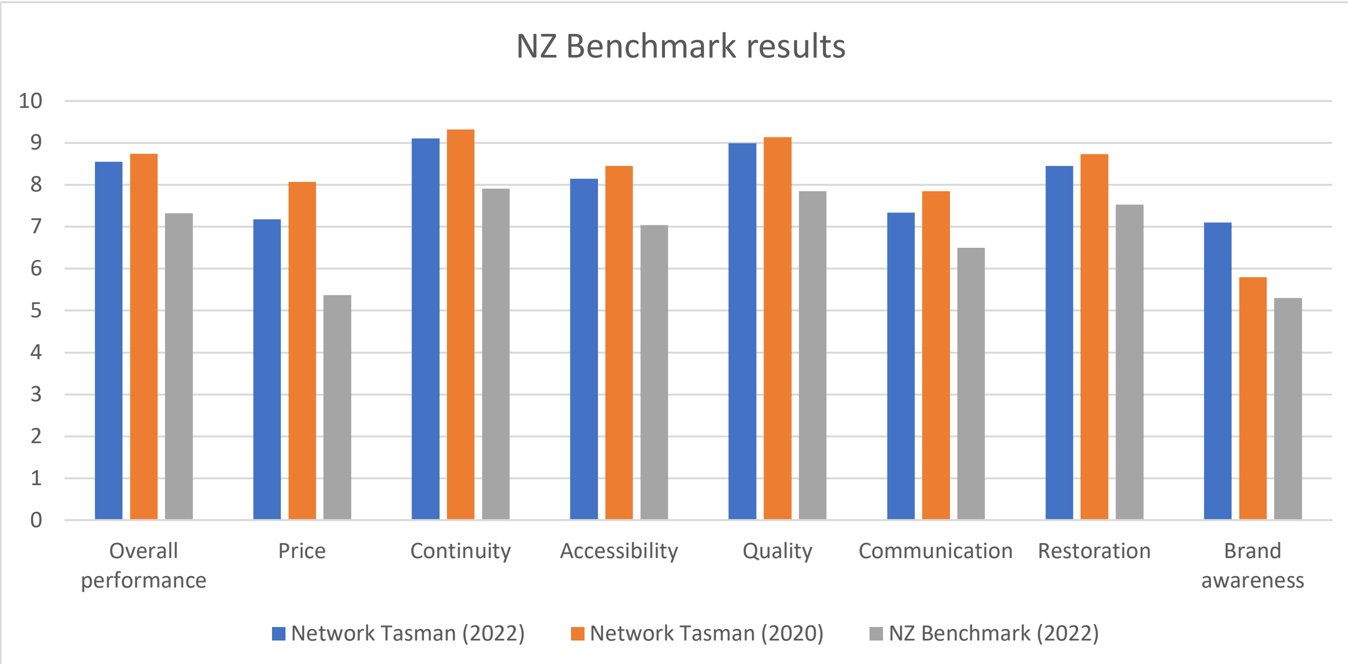
Network Tasman does not have a formal pricing strategy as defined in the Information Disclosure Determination. However, the following summarises Network Tasman's current perspectives on future pricing.

8.1. Consumer perspectives on pricing

Network Tasman conducted a consumer survey in late 2022 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 with regard to service quality, continuity and restoration. Consumers gave Network Tasman an overall performance satisfaction rating of 8.55/10.

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.



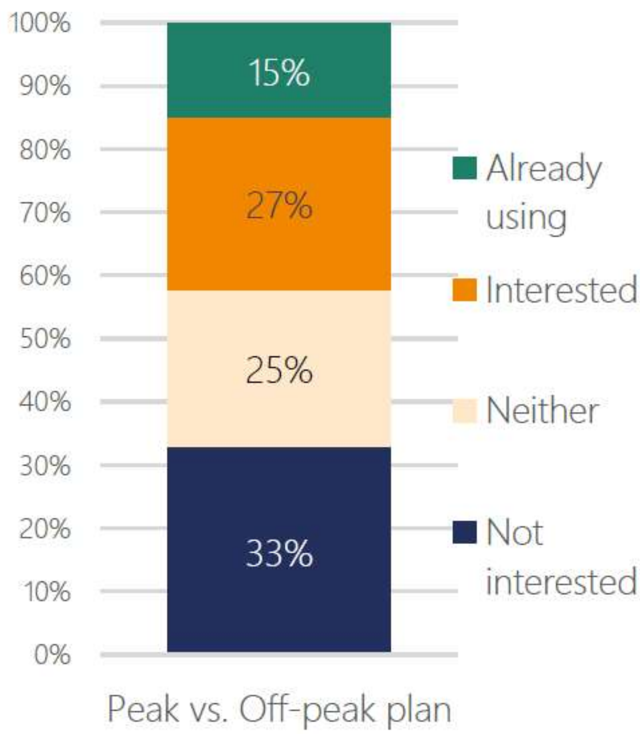
Consumers were surveyed on price structures. Just one-third of consumers indicated they would not be interested in a peak/off-peak plan. This result is similar to the responses to this question in previous consumer surveys. These results have contributed to Network Tasman's introduction of a Peak/Off-peak tariff from 1 April 2023.

The presence of the retail market sitting between distribution prices and the bills consumers see each billing cycle mitigates the risk of Network Tasman introducing a tariff that some consumers may not wish to receive. Retailers are able to, and many have indicated they will, repackage our Peak/Off-peak tariff into a standard flat kWh charge for those consumers that 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.

FIGURE 3: INTEREST IN PEAK VS OFF-PEAK PLAN (2022)



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, the vast majority 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.

8.2. Future Pricing Strategy

Looking to the future, technological change indicates the way consumers use electricity may change significantly. Solar panels, battery storage and electric vehicles are forecast to become more commonplace over time, as technological improvements and scale economies lower costs. Simplistic 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 and how quickly adoption will occur, a small but growing number of consumers have taken an interest in the options becoming available to them.

The commercial implications of electric vehicles and solar panels under existing price structures are countervailing, to a degree. As more consumers on our network purchase electric vehicles, their use of the network will increase along with their lines charges. Similarly, as more consumers install solar panels, their electricity consumption and lines charges are expected to fall. Recovering a higher proportion of revenues via fixed charges can mitigate the effects of these, as can time-of-use based consumption prices.

Network Tasman has the second-highest rooftop solar PV penetration of all distributors in New Zealand. Approximately 4.3% of connections on Network Tasman's network have solar generation and about 2.5% of connections in the combined Network Tasman and Nelson Electricity network areas have an electric vehicle, up from 3.5% and 2% twelve months ago respectively. Although these figures are starting from a low base they are beginning to exhibit strong 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 has taken a significant step in its roadmap to modernise its prices with the introduction of a mandatory Peak/Off-peak tariff for Group 1 and 2 consumers. The new tariff will provide consumers with increasingly strong incentives to shift discretionary load away from periods of network peak demand. Initial price differentials have been moderated to manage the bill effect of the new tariff. Network Tasman plans to incrementally increase the differential between the peak and off-peak tariffs to provide consumers with stronger incentives to shift load away from the peak.

The key milestones for 2023/24 on Network Tasman's reform roadmap are:

- to develop a long-run marginal cost model that can inform the proportion of revenue Network Tasman should be recovering from fixed and variable charges and the price levels for those variable charges.
- To undertake a full review of Group 3 prices.

Figure 4: Network Tasman pricing roadmap

2022/23 (complete)

- **Implement**
  - first round of LFC fixed phase-out
  - Updated new load policy to introduce option of profiled connections in congested locations
- **Develop**
  - TOU prices for Groups 1 and 2
  - allocation methodology for transmission costs to reflect new TPM

2023/24

- **Implement**
  - TOU prices for Groups 1 and 2
  - Second round of LFC phase-out
  - New cost allocation methodology for transmission costs under the new TPM.
- **Develop**
  - LRMC model to inform fixed/variable price split
- **Review**
  - Undertake a full review of Group 3 prices
- **Monitor**
  - Effect of new Group 1 and 2 TOU prices

2024/25

- **Implement**
  - Changes to Group 3 prices identified in 23/24 review
  - Third round of LFC phase-out
- **Assess**
  - Effectiveness of Group 1 and 2 TOU prices and consider modifications/improvements.
  - Refinements to existing prices as developments (technological, retailer/consumer preference, DER penetration/economics, etc) occur.
  - Opportunities to rationalize tariffs or price categories.
- **Monitor**
  - Effect of new Group 3 prices

2025/26

- **Implement**
  - Fourth round of LFC phase-out
- **Assess**
  - Refinements to existing prices as developments (technological, retailer/consumer preference, DER penetration/economics, etc) occur.
  - Opportunities to rationalize tariffs or price categories.

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*

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.

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.

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

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 measuring 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.

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.

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.

Regulated 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

Customer Group	Number of ICP's	Coincident Maximum Demand	Capacity	Total Consumption	RAB Value Allocated
	#	kW	kVA	kWh	$(m)
Group 1	39,445	57,199	591,668	274,356,327	$102.61
Group 2	2,965	20,271	134,250	107,406,369	$50.97
Group 3	194	25,890	114,151	156,388,570	$44.32
Group 6	2	15,023	N/A	111,953,543	$2.65
Total	42,605	118,555	840,069	538,151,266	$200.46

*Standard price categories

Appendix D: Network Tasman prices effective from 01 April 2023

Network Tasman Limited Pricing From 01 April 2023 to 31 March 2024

				2022-23					2023-24				
Price description	Price Code	Approx Connections with this price	Unit of measure	Distribution price	Transmission price	Pass through price	Delivery price	Discount	Distribution price	Transmission price	Pass through price	Delivery price	Discount
Metered connections 15-150 kVA capacity													
Low-Use Residential (<8,000 kWh pa) 15 kVA connections. Price Category 1RL													
Daily fixed price	1RL	19,161	$/day	0.2382	0.0603	0.0015	**0.3000**	0.0000	0.3585	0.0900	0.0015	**0.4500**	0.0000
Uncontrolled	1RLANY	18,485	$/kWh	0.0637	0.0202	0.0008	**0.0847**	0.0313	0.0623	0.0132	0.0009	**0.0764**	0.0313
Day (of day/night)	1RLDAY	692	$/kWh	0.0719	0.0205	0.0010	**0.0934**	0.0350	0.0681	0.0148	0.0011	**0.0840**	0.0350
Default	1RLDEF		$/kWh						0.0623	0.0132	0.0009	**0.0764**	0.0313
Night	1RLNIT	2,264	$/kWh	0.0402	0.0063	0.0002	**0.0467**	0.0106	0.0331	0.0083	0.0003	**0.0417**	0.0106
Off Peak	1RLOFP		$/kWh						0.0526	0.0132	0.0009	**0.0667**	0.0250
Peak	1RLPEK		$/kWh						0.0704	0.0132	0.0009	**0.0845**	0.0366
Controlled water	1RLWSR	15,299	$/kWh	0.0413	0.0085	0.0004	**0.0502**	0.0144	0.0368	0.0093	0.0005	**0.0466**	0.0144
Generation Export	1RLGEN	950	$/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	16,479	$/day	0.7868	0.2082	0.0030	**1.0000**	0.0000	0.8238	0.2332	0.0030	**1.0600**	0.0000
Uncontrolled	1RSANY	15,952	$/kWh	0.0397	0.0123	0.0008	**0.0528**	0.0313	0.0411	0.0066	0.0008	**0.0485**	0.0313
Day (of day/night)	1RSDAY	554	$/kWh	0.0454	0.0151	0.0010	**0.0615**	0.0350	0.0469	0.0082	0.0010	**0.0561**	0.0350
Default	1RSDEF		$/kWh						0.0411	0.0066	0.0008	**0.0485**	0.0313
Night	1RSNIT	1,946	$/kWh	0.0115	0.0031	0.0002	**0.0148**	0.0106	0.0119	0.0017	0.0002	**0.0138**	0.0106
Off Peak	1RSOFP		$/kWh						0.0314	0.0066	0.0008	**0.0388**	0.0250
Peak	1RSPEK		$/kWh						0.0492	0.0066	0.0008	**0.0566**	0.0366
Controlled water	1RSWSR	13,107	$/kWh	0.0151	0.0050	0.0004	**0.0205**	0.0144	0.0156	0.0027	0.0004	**0.0187**	0.0144
Generation Export	1RSGEN	666	$/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	3,854	$/day	0.7868	0.2082	0.0030	**1.0000**	0.0000	0.8238	0.2332	0.0030	**1.0600**	0.0000
Uncontrolled	1GLANY	3,566	$/kWh	0.0397	0.0123	0.0008	**0.0528**	0.0313	0.0411	0.0066	0.0008	**0.0485**	0.0313
Day (of day/night)	1GLDAY	292	$/kWh	0.0454	0.0151	0.0010	**0.0615**	0.0350	0.0469	0.0082	0.0010	**0.0561**	0.0350
Default	1GLDEF		$/kWh						0.0411	0.0066	0.0008	**0.0485**	0.0313
Night	1GLNIT	362	$/kWh	0.0115	0.0031	0.0002	**0.0148**	0.0106	0.0119	0.0017	0.0002	**0.0138**	0.0106
Off Peak	1GLOFP		$/kWh						0.0314	0.0066	0.0008	**0.0388**	0.0250
Peak	1GLPEK		$/kWh						0.0492	0.0066	0.0008	**0.0566**	0.0366
Controlled water	1GLWSR	1,015	$/kWh	0.0151	0.0050	0.0004	**0.0205**	0.0144	0.0156	0.0027	0.0004	**0.0187**	0.0144
Generation Export	1GLGEN	37	$/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	2,809	$/kVA/day	0.0751	0.0193	0.0006	**0.0950**	0.0000	0.0778	0.0261	0.0006	**0.1045**	0.0000
Uncontrolled	2ANY	2,366	$/kWh	0.0505	0.0068	0.0008	**0.0581**	0.0287	0.0508	0.0066	0.0008	**0.0582**	0.0287
Day (of day/night)	2DAY	514	$/kWh	0.0578	0.0076	0.0008	**0.0662**	0.0322	0.0581	0.0073	0.0008	**0.0662**	0.0322
Default	2DEF		$/kWh						0.0508	0.0066	0.0008	**0.0582**	0.0287
Night	2NIT	612	$/kWh	0.0203	0.0000	0.0000	**0.0203**	0.0084	0.0204	0.0000	0.0000	**0.0204**	0.0084
Off Peak	2OFP		$/kWh						0.0392	0.0066	0.0008	**0.0466**	0.0230
Peak	2PEK		$/kWh						0.0586	0.0066	0.0008	**0.0660**	0.0325
Controlled water	2WSR	695	$/kWh	0.0282	0.0000	0.0004	**0.0286**	0.0125	0.0283	0.0000	0.0004	**0.0287**	0.0125
Generation Export	2GEN	134	$/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) cor		0											
Daily capacity price	2LLFC	66	$/day	0.2745	0.0239	0.0016	**0.3000**	0.0000	0.4161	0.0323	0.0016	**0.4500**	0.0000
Uncontrolled	2LANY	60	$/kWh	0.1089	0.0213	0.0008	**0.1310**	0.0287	0.1029	0.0290	0.0013	**0.1332**	0.0287
Day (of day/night)	2LDAY	6	$/kWh	0.1146	0.0236	0.0010	**0.1392**	0.0322	0.1102	0.0297	0.0013	**0.1412**	0.0322
Default	2LDEF		$/kWh						0.1029	0.0290	0.0013	**0.1332**	0.0287
Night	2LNIT	12	$/kWh	0.0833	0.0098	0.0002	**0.0933**	0.0084	0.0725	0.0224	0.0005	**0.0954**	0.0084
Off Peak	2LOFP		$/kWh						0.0913	0.0290	0.0013	**0.1216**	0.0230
Peak	2LPEK		$/kWh						0.1107	0.0290	0.0013	**0.1410**	0.0325
Controlled water	2LWSR	32	$/kWh	0.0858	0.0156	0.0002	**0.1016**	0.0125	0.0804	0.0224	0.0009	**0.1037**	0.0125
Generation Export	2LGEN	2	$/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	0.2745	0.0239	0.0016	**0.3000**	0.0000	0.4161	0.0323	0.0016	**0.4500**	0.0000
Uncontrolled	2HANY	5	$/kWh	0.1833	0.0333	0.0011	**0.2177**	0.0287	0.1740	0.0529	0.0018	**0.2287**	0.0287
Day (of day/night)	2HDAY	0	$/kWh	0.2024	0.0232	0.0002	**0.2258**	0.0322	0.1813	0.0536	0.0018	**0.2367**	0.0322
Default	2HDEF		$/kWh						0.1740	0.0529	0.0018	**0.2287**	0.0287
Night	2HNIT	0	$/kWh	0.1799	0.0000	0.0000	**0.1799**	0.0084	0.1436	0.0463	0.0010	**0.1909**	0.0084
Off Peak	2HOFP		$/kWh						0.1624	0.0529	0.0018	**0.2171**	0.0230
Peak	2HPEK		$/kWh						0.1818	0.0529	0.0018	**0.2365**	0.0325
Controlled water	2HWSR	2	$/kWh	0.1882	0.0000	0.0000	**0.1882**	0.0125	0.1515	0.0463	0.0014	**0.1992**	0.0125
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	35	$/kVA/day	0.4323	0.0635	0.0042	**0.5000**	0.0978	0.4585	0.0673	0.0042	**0.5300**	0.0978
Uncontrolled	HLFANY	25	$/kWh	0.0123	0.0018	0.0002	**0.0143**	0.0076	0.0129	0.0017	0.0002	**0.0148**	0.0076
Day (of day/night)	HLFDAY	10	$/kWh	0.0134	0.0020	0.0002	**0.0156**	0.0079	0.0141	0.0019	0.0002	**0.0162**	0.0079
Default	HLFDEF		$/kWh						0.0129	0.0017	0.0002	**0.0148**	0.0076
Night	HLFNIT	11	$/kWh	0.0038	0.0006	0.0002	**0.0046**	0.0030	0.0038	0.0006	0.0002	**0.0046**	0.0030
Off Peak	HLFOFP		$/kWh						0.0099	0.0017	0.0002	**0.0118**	0.0061
Peak	HLFPEK		$/kWh						0.0156	0.0017	0.0002	**0.0175**	0.0090
Controlled water	HLFWSR	8	$/kWh	0.0056	0.0008	0.0002	**0.0066**	0.0054	0.0059	0.0008	0.0002	**0.0069**	0.0054
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

Large Commercial ≥150 kVA capacity, TOU metered (Group 3)													
Category 3.1													
Anytime demand (Distribution)	AnyDem31	4	$/kVA/day	0.1128	0.0256	0.0048	0.1432	0.0126	0.1196	0.0000	0.0060	0.1256	0.0126
RCPD kW demand(1)	WinDem3.1	4	$/kW/day	0.0371	0.2378	0.0012	0.2761	0.0000					
Anytime demand (Transmission	ANY_T	4	$/kVA/day						0.0000	0.1116	0.0000	0.1116	0.0000
Summer day	SD31	4	$/kWh	0.0054	0.0000	0.0000	0.0054	0.0020	0.0063	0.0000	0.0000	0.0063	0.0020
Summer night	SN31	4	$/kWh	0.0027	0.0000	0.0000	0.0027	0.0011	0.0031	0.0000	0.0000	0.0031	0.0011
Winter day	WD31	4	$/kWh	0.0095	0.0000	0.0000	0.0095	0.0034	0.0110	0.0000	0.0000	0.0110	0.0034
Winter night	WN31	4	$/kWh	0.0027	0.0000	0.0000	0.0027	0.0011	0.0031	0.0000	0.0000	0.0031	0.0011
Generation	3.1GEN	4	$/kWh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Category 3.3													
Anytime demand (Distribution)	AnyDem33	6	$/kVA/day	0.1355	0.0256	0.0048	0.1659	0.0163	0.1436	0.0000	0.0060	0.1496	0.0163
RCPD kW demand(1)	WinDem3.3	6	$/kW/day	0.0371	0.2378	0.0012	0.2761	0.0000					
Anytime demand (Transmission	ANY_T	6	$/kVA/day						0.0000	0.1116	0.0000	0.1116	0.0000
Summer day	SD33	6	$/kWh	0.0161	0.0000	0.0000	0.0161	0.0059	0.0187	0.0000	0.0000	0.0187	0.0059
Summer night	SN33	6	$/kWh	0.0086	0.0000	0.0000	0.0086	0.0030	0.0100	0.0000	0.0000	0.0100	0.0030
Winter day	WD33	6	$/kWh	0.0412	0.0000	0.0000	0.0412	0.0149	0.0479	0.0000	0.0000	0.0479	0.0149
Winter night	WN33	6	$/kWh	0.0086	0.0000	0.0000	0.0086	0.0030	0.0100	0.0000	0.0000	0.0100	0.0030
Generation	3.3GEN	6	$/kWh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Category 3.4													
Anytime demand (Distribution)	AnyDem34	177	$/kVA/day	0.1446	0.0256	0.0048	0.1750	0.0174	0.1533	0.0000	0.0060	0.1593	0.0174
RCPD kW demand(1)	WinDem3.4	177	$/kW/day	0.0371	0.2378	0.0012	0.2761	0.0000					
Anytime demand (Transmission	ANY_T	177	$/kVA/day						0.0000	0.1116	0.0000	0.1116	0.0000
Summer day	SD34	177	$/kWh	0.0161	0.0000	0.0000	0.0161	0.0059	0.0187	0.0000	0.0000	0.0187	0.0059
Summer night	SN34	177	$/kWh	0.0086	0.0000	0.0000	0.0086	0.0030	0.0100	0.0000	0.0000	0.0100	0.0030
Winter day	WD34	177	$/kWh	0.0412	0.0000	0.0000	0.0412	0.0149	0.0479	0.0000	0.0000	0.0479	0.0149
Winter night	WN34	177	$/kWh	0.0086	0.0000	0.0000	0.0086	0.0030	0.0100	0.0000	0.0000	0.0100	0.0030
Generation	3.4GEN	177	$/kWh	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Category 3.5													
Anytime demand (Distribution)	AnyDem35	2	$/kVA/day	0.1355	0.0256	0.0048	0.1659	0.0163	0.1436	0.0000	0.0060	0.1496	0.0163
RCPD kW demand(1)	WinDem3.5	2	$/kW/day	0.0371	0.2378	0.0012	0.2761	0.0000					
Anytime demand (Transmission	ANY_T	2	$/kVA/day						0.0000	0.1116	0.0000	0.1116	0.0000
Summer day	SD35	2	$/kWh	0.0109	0.0000	0.0000	0.0109	0.0039	0.0127	0.0000	0.0000	0.0127	0.0039
Summer night	SN35	2	$/kWh	0.0068	0.0000	0.0000	0.0068	0.0025	0.0079	0.0000	0.0000	0.0079	0.0025
Winter day	WD35	2	$/kWh	0.0352	0.0000	0.0000	0.0352	0.0128	0.0409	0.0000	0.0000	0.0409	0.0128
Winter night	WN35	2	$/kWh	0.0068	0.0000	0.0000	0.0068	0.0025	0.0079	0.0000	0.0000	0.0079	0.0025
Generation	3.5GEN	2	$/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	kVAr	3	$/kVAr/day	0.2963	0.0000	0.0000	0.2963	0.0000	0.3111	0.0000	0.0000	0.3111	0.0000
Individually priced categories													
Cat 6.1 - Annual charge	6.1	1	$ per annum	234,732	1,362,685	832	1,598,247	27,280	245,999	1,121,577	758	1,368,335	27,355
Cat 6.2 - Annual charge	6.2	1	$ per annum	251,573	299,594	832	551,997	40,552	263,647	188,276	758	452,680	40,663
Cat CB - Annual charge	CobbLine	1	$ per annum	1,494,124	217,444	0	1,711,569	0	1,601,989	227,376	0	1,829,367	0
Cat MAT - Annual charge	MAT	1	$ per annum	20,042	67,777	0	87,819	0	10,425	2,730	0	13,155	0
Embedded Network	NEL	1	$ per annum	0	1,731,703	0	1,731,703	0	0	1,557,510	0	1,557,510	0
Individual categories	EAL[1]	4	$/MWh[1]	0.0000	0.0000	0.1413	0.1413	0.0000	0.0000	0.0000	0.1484	0.1484	0.0000
Unmetered connections (Group 0):Low capacity: Electric fences, communications etc													
Daily fixed price	0UNM	76	$/day	0.4216	0.1234	0.0050	0.5500	0.0000	0.5197	0.0753	0.0050	0.6000	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	0.00094	0.00026	0.00001	0.00121	0.0000	0.00098	0.00016	0.00001	0.00115	0.0000

Note:

All prices exclude GST
Note (1). The RCPD price ends 31 March 2023, and from April 2023 is replace by the ANY_T price
Default: Price for AMI metered connections where uncontrolled energy is not reported on the Off-Peak/Peak pricing combination. New from April 2023
Day: 0700 to 2300. Night: 2300 to 0700. Applies to all days
Peak: 0700 to 2300 Monday to Friday inclusive. Off Peak: all day Saturday and Sunday and 2300 to 0700 Monday to Friday inclusive. Peak/Off-Peak for uncontrolled energy use at AMI metered connections. New from April 2023
AMI metering. These are "smart" meters that include advances features such as 2-way communication.
Summer: October to April; Winter: May to September
HLF pricing is best suited to high consumption Group 1&2 consumers with load factors exceeding 30%
EAL - NTL passes Electricity Authority levies to individually priced connections on a pass through basis
Power factor price code kVAr is applied on a case by case basis only.

Appendix E: Proportion of Target Revenue collected via each price component

For April 2023 to March 2024							
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	19,197	$/day	6.4%	1.61%	0.0%	8.1%
Uncontrolled	1RLANY	2,403	$/kWh	0.8%	0.3%	0.0%	1.1%
Day (of day/night)	1RLDAY	703	$/kWh	0.2%	0.1%	0.0%	0.2%
Default	1RLDEF	322	$/kWh	0.1%	0.0%	0.0%	0.1%
Night	1RLNIT	2,267	$/kWh	0.1%	0.0%	0.0%	0.1%
Off Peak	1RLOFP	7,119	$/kWh	2.0%	1.0%	0.1%	3.1%
Peak	1RLPEK	8,659	$/kWh	3.0%	1.2%	0.1%	4.3%
Controlled water	1RLWSR	15,327	$/kWh	1.6%	0.7%	0.0%	2.3%
Generation Export	1RLGEN	962	$/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	16,416	$/day	12.5%	3.5%	0.0%	16.0%
Uncontrolled	1RSANY	2,103	$/kWh	0.4%	0.2%	0.0%	0.6%
Day (of day/night)	1RSDAY	545	$/kWh	0.1%	0.1%	0.0%	0.1%
Default	1RSDEF	276	$/kWh	0.0%	0.0%	0.0%	0.1%
Night	1RSNIT	1,934	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	1RSOFP	6,216	$/kWh	0.7%	0.7%	0.1%	1.5%
Peak	1RSPEK	7,284	$/kWh	1.6%	0.8%	0.1%	2.5%
Controlled water	1RSWSR	13,044	$/kWh	0.1%	0.2%	0.0%	0.4%
Generation Export	1RSGEN	675	$/kWh	0.0%	0.0%	0.0%	0.0%
Non-Residential 15kVA connections. Price Category 1GL							
Daily fixed price	1GL	3,838	$/kWh	2.9%	0.8%	0.0%	3.7%
Uncontrolled	1GLANY	771	$/kWh	0.1%	0.1%	0.0%	0.2%
Day (of day/night)	1GLDAY	294	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	1GLDEF	56	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	1GLNIT	364	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	1GLOFP	1,128	$/kWh	0.1%	0.1%	0.0%	0.2%
Peak	1GLPEK	1,592	$/kWh	0.3%	0.1%	0.0%	0.4%
Controlled water	1GLWSR	1,001	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	1GLGEN	38	$/kWh	0.0%	0.0%	0.0%	0.0%
General (20-150 kVA) connections. Price Category 2							
Daily fixed price	2	2,814	$/kVA/day	9.4%	3.2%	0.1%	12.6%
Uncontrolled	2ANY	517	$/kWh	0.8%	0.3%	0.0%	1.1%
Day (of day/night)	2DAY	514	$/kWh	1.3%	0.4%	0.0%	1.7%
Default	2DEF	37	$/kWh	0.1%	0.0%	0.0%	0.1%
Night	2NIT	612	$/kWh	0.2%	0.0%	0.0%	0.2%
Off Peak	2OFP	730	$/kWh	0.9%	0.4%	0.0%	1.3%
Peak	2PEK	1,078	$/kWh	2.1%	0.5%	0.1%	2.7%
Controlled water	2WSR	692	$/kWh	0.1%	0.0%	0.0%	0.1%
Generation Export	2GEN	134	$/kWh	0.0%	0.0%	0.0%	0.0%
Residential Low Fixed (20 and 30 kVA capacity) connection		0					
Daily fixed price	2LLFC	67	$/day	0.0%	0.0%	0.0%	0.0%
Uncontrolled	2LANY	9	$/kWh	0.0%	0.0%	0.0%	0.0%
Day (of day/night)	2LDAY	7	$/kWh	0.0%	0.0%	0.0%	0.0%
Default	2LDEF	1	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	2LNIT	11	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	2LOFP	23	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	2LPEK	28	$/kWh	0.0%	0.0%	0.0%	0.1%
Controlled water	2LWSR	31	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	2LGEN	3	$/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	2	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	2HPEK	2	$/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	34	$/kVA/day	1.0%	0.2%	0.0%	1.2%
Uncontrolled	HLFANY	6	$/kWh	0.0%	0.0%	0.0%	0.0%
Day (of day/night)	HLFDAY	10	$/kWh	0.0%	0.0%	0.0%	0.1%
Default	HLFDEF	0	$/kWh	0.0%	0.0%	0.0%	0.0%
Night	HLFNIT	11	$/kWh	0.0%	0.0%	0.0%	0.0%
Off Peak	HLFOFP	8	$/kWh	0.0%	0.0%	0.0%	0.0%
Peak	HLFPEK	9	$/kWh	0.0%	0.0%	0.0%	0.0%
Controlled water	HLFWSR	8	$/kWh	0.0%	0.0%	0.0%	0.0%
Generation Export	HLFGEN	2	$/kWh	0.0%	0.0%	0.0%	0.0%
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%
RCPD kW demand	WinDem	4	$/kW/day	0.0%	0.2%	0.0%	0.2%
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	0	$/kVA/day	0.3%	0.0%	0.0%	0.3%
RCPD kW demand	WinDem	0	$/kW/day	0.0%	0.2%	0.0%	0.2%
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	180	$/kVA/day	6.4%	0.0%	0.3%	6.7%
RCPD kW demand	WinDem	180	$/kW/day	0.0%	4.7%	0.0%	4.7%
Summer day	SD34	180	$/kWh	1.8%	0.0%	0.0%	1.8%
Summer night	SN34	180	$/kWh	0.3%	0.0%	0.0%	0.3%
Winter day	WD34	180	$/kWh	3.6%	0.0%	0.0%	3.6%
Winter night	WN34	180	$/kWh	0.3%	0.0%	0.0%	0.3%
Category 3.5							
Anytime kVA demand	AnyDem35	0	$/kVA/day	0.4%	0.0%	0.0%	0.4%
RCPD kW demand	WinDem	0	$/kW/day	0.0%	0.3%	0.0%	0.3%
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)2							
Cat 6.1 - Annual charge	6.1	1	$ per annum	0.5%	2.8%	0.0%	3.4%
Cat 6.2 - Annual charge	6.2	1	$ per annum	0.6%	0.5%	0.0%	1.0%
Cat CB - Annual charge	CB	1	$ per annum	4.0%	0.6%	0.0%	4.6%
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%	3.9%	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	70	$/day	0.0%	0.0%	0.0%	0.0%
Unmetered connections (Group 0): Streetlighting - General							
Streetlight only connection	0S	24	$/day	0.0%	0.0%	0.0%	0.0%
Capacity price for streetlights	0STL	0	$/W/day	0.4%	0.1%	0.0%	0.5%

Appendix F: Methodology for passing-on settlement residue payments

In November 2022, the Electricity Authority published a decision to amend the Code to require distributors to pass through settlement residue payments (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 every month to customers that pay lines charges directly. Distributors must develop a methodology for allocating settlement residue to their customers that gives effect to the purpose of the Code amendment.

Accordingly, Network Tasman's methodology for passing-on monthly settlement residues received from Transpower for any trading period on or after 1 April 2023 is described below.

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

A customer's transmission charges at a connection location will be calculated by multiplying the transmission prices published on Network Tasman's regulated price schedule by the equivalent billing quantities used by that customer at the connection location.

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

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

The formula below summarises the methodology to be used:

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

Where:

x = customer

y = connection location

Monthly settlement residue$_y$ = Monthly settlement residue 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 will be based on initial billing quantities and will not be subject to adjustments.

Payments to customers will be made monthly.