Northpower

Pricing Methodology

1 April 2020 – 31 March 2021

1 Introduction

Northpower owns and operates the electricity distribution network covering the Whangarei and Kaipara regions, delivering electricity to more than 59,000 homes and businesses. The network covers a wide geographic area from Pouto in the south to Bland Bay in the north, and includes Whangarei city and Dargaville township, as well as extensive rural areas.

There are six major industrial consumers on our network, whom collectively consume 47% of the electricity conveyed across the network. In addition there are approximately:

- 49,000 residential dwellings
- 5,000 farm related connections (sheds, pumps, farm utilities)
- 2,500 commercial premises (shops, offices, workshops)

We recover the cost of owning and operating the network through a combination of standard (i.e. published) and non-standard prices for electricity lines services, and capital contributions for new connections. This document describes our methodology for setting our prices for electricity lines services.

We are wholly owned by the Northpower Electric Power Trust, which is a consumer trust. As such, we are effectively owned by our consumers.

2 Regulatory Context

2.1 Commerce Act

The Commerce Commission ("Commission") regulates markets where competition is limited, including electricity distribution services, under the Commerce Act 1986 ("the Act"). Under the Act, an electricity distribution business ("EDB") can be subject to information disclosure regulation, or both information disclosure and price-quality regulation.

Price-quality Regulation

Price-quality regulation is the process whereby the Commission sets the Maximum Allowable Revenue that an EDB may receive from distribution prices. As Northpower meets the definition of an exempt consumer owned EDB (because it is owned by consumers via a consumer trust, trustees are elected, over 90% of consumers benefit from distributions, and there are less than 150,000 ICPs), it is not subject to price-quality regulation.

Information Disclosure Regulation

Information disclosure regulation is the process whereby EDBs are required to publish information about their performance. The purpose of this regulation is to ensure that information is available to interested persons to assess whether the purpose of Part 4 of the Act is being met. The requirements are set out in the Electricity Distribution Information Disclosure Determination 2012 (including subsequent amendments) ("EDIDD").

This document contains the information required to be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the EDIDD.

2.2 Electricity Authority

We have developed our prices with reference to the Electricity Authority's Pricing Principles ("Pricing Principles") and its August 2019 Guidance Note. The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained, and economically rational methodology. While the Pricing Principles are voluntary, the Disclosure Determination requires each EDB to either demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistency.

Appendix 3 sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

2.3 Low Fixed Charge Regulations

We are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 ("Low Fixed Charge Regulations"). These regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equals any other permanent place of residence price option for consumers using 8,000kWh per annum.

2.4 Electricity Code

We have developed our policies and procedures for installation and connection of distributed generation in accordance with the requirements of Part 6 (Connection of Distributed Generation) of the Electricity Industry Participation Code 2010 ("the Code").

3 Pricing Strategy

Our pricing strategy is to transition network pricing to be more cost reflective and responsive to the evolving market and the changing ways that consumers are using electricity.

Electricity networks are like roads in that they can become congested at peak times of the day. Cost reflective pricing uses price signals to demonstrate when there is capacity in our network (through lower prices), and when the network is more congested (through higher prices).

Consuming more electricity at peak times may mean that we might need to incur cost to increase the capacity of our network in the future.

Emerging technology such as electric vehicles, solar panels, and batteries are changing how we consume, generate, and manage our electricity. We think it is important that pricing evolves to encourage efficient use of the network to minimise the cost of capacity increases, reduce prices for consumers in the long term and to ensure fair outcomes for all consumers on our network.

This strategy will broadly result in fixed prices increasing, variable prices decreasing, and differentiated pricing being available based on the time of day.

3.1 Network Capacity

Pricing can have a role in alleviating congestion and capacity constraints on a distribution network through sending appropriate price signals. For the majority of our network there are no capacity constraints. However, we do have some emerging challenges.

- Helena Bay and surrounding areas sometimes experience congestion issues around holiday periods due to the high proportion of holiday homes and associated influx of holiday makers, leading to additional network demand for short periods of time. This is compounded by the remote location, meaning it is a significant distance from the nearest substation.
- Mangawhai has experienced significant growth in recent years, resulting in the 11kV backfeeding previously used to provide N-1 security no longer having the required capacity, placing Mangawhai on N security at peak times. There is significant growth planned for Mangawhai including a supermarket in the near future, and as such a second line or an alternative arrangement to increase security of supply is being considered.
- There is significant enquiry around large scale distributed generation on the network. In some cases the scale of these enquiries generally mean that, if any of the projects were to go ahead, they would effectively take up all of the existing capacity to inject generation in that part of the network, requiring future network upgrades.

As part of our network planning processes, we now actively consider non-network alternative options to address system constraints. We consider if local generation or balancing options may be viable, and if contracted demand response schemes may be able to defer or avoid asset based solutions.

In the current energy environment, the applicability of non-network solutions is limited for very high load situations, however this situation may change in future as practical options emerge in the market.

Congestion is likely to be an emerging issue more generally on our networks into the future depending on the changing energy requirements of consumers and large scale distributed generation. Growth in our region tends to be outward rather than through increasing density, and as such new assets are required to extend the geographical reach of the network. This has the effect of increasing the capacity of the network in the places it is needed, noting increases in substation and 11kV capacity can be required.

Growth in places where the network already exists such as on the the outskirts of Whangarei could potentially be absorbed through active network management once constraints are reached. Also electrification such as widespread adoption of electric vehicles, commercial transport, and industrial process heat could also increase demand for electricity, and create congestion.

In terms of these more general trends, we consider it important to get pricing structures in place now that encourage consumers to think about where prices are going in the long term, and send appropriate signals as consumers consider making long term investment decisions in relation to distributed generation, storage, electric vehicles, heating, and other appliances. Over the next 12 months we will be considering the extent to which we should or reasonably can include locational price signals to signal capacity constraints in particular areas.

3.2 Smart Meter uptake

Cost reflective pricing is heavily reliant on smart meter uptake, enabling half hour consumption reads to calculate consumers' electricity consumption in different ways, such as by peak, shoulder, and off peak periods to facilitate Time of Use billing. The meters also need to be able to communicate reliably and consistently.

We currently have 86% of connected ICPs on our network with smart metering installed and 81% are marked as communicating in the Registry.

3.3 Time of Use

We have introduced 'Time of Use' pricing for all residential and small to medium businesses effective from 1 April 2020. Time of Use pricing is mandatory for all consumers on our DM1, DM3, DM7, ND1 and ND2 price plans, with a default option available if retailers are unable to comply with the data requirements. The prices have been set to be revenue neutral between those on the relevant Time of Use plan and those on the applicable default plan (e.g. between Residential Low User – Default and Residential Low User – Time of Use).

The Time of Use pricing structure will, over time, have increasingly higher prices during peak times of the day when the network is more congested, and lower rates during off peak times when there is plenty of capacity in the network. This indicates to consumers that consuming electricity off peak may save us money compared to consuming it at peak times, and shares this benefit with consumers who consume off peak. Over time, we expect that within the Time of Use pricing structures, the fixed daily price will increase and the variable charges will decrease while still retaining a peak pricing charge.

3.3.1. Process

In selecting Time of Use we considered a number of pricing options, including Customer Peak Demand, Network Peak Demand, Installed Capacity, and Nominated Capacity. We assessed these options against a number of criteria, including their ability to:

- Manage peak loads
- Improve utilisation of network assets
- Signal the best time to charge EV's
- Ensure all consumers contribute fairly to fixed and variable costs
- Reduce incremental cost to consume electricity
- Reduce undesirable cross subsidies
- Give consumers the ability to manage their bill (where Retailers pass through transparently)
- Be simple for consumers to understand
- Manage our revenue risk

We also conducted a trial in 2019-2020, which has enabled us to test billing processes and gain insights and feedback from consumers and retailers.

We have not been able to accurately identify the volume of consumption in the time periods or gauge the change in consumer behaviour resulting from the trial, due to the relatively small trial population and self selection bias.

We selected ToU as our preferred cost reflective pricing methodology following feedback that this option is preferred by consumers and retailers, on the basis it is the easiest option for consumers to understand and respond to in the event that retailers pass the charges through, and the most practical option for retailers to implement. We have worked closely with Top Energy to align our new pricing structures, to reduce the complexity for retailers and provide one pricing structure for the whole of Northland for residential and small to medium business consumers.

Introduction of Time of Use sets us up for the future by signalling to consumers when and how to efficiently use the network to reduce incremental costs as demand grows. In practical terms, it sends efficient pricing signals to consumers purchasing electric vehicles, solar panels, and batteries as to the realistic costs of and savings from these investments so they can determine when is best to charge, and whether the investments are efficient. It also means the structure is in place for when stronger price signals are required in the future.

The Government has recently signalled that it will repeal the Low Fixed Charges Regulations. Within the Time of Use pricing structure, this change will enable the fixed daily price to be increased (reflecting the fixed cost nature of our network) and the variable charges within the Time of Use prices to be decreased, while still retaining a peak pricing charge.

3.3.2. Pricing Structure

We have implemented a peak/shoulder/off-peak pricing structure for residential consumers and small to medium businesses, reflecting our network loads. The start and stop times selected largely reflect the times of peak load on our networks, and the times that the majority of RCPD peaks fall within. While this structure does not exactly reflect either of our or Top Energy's networks, we have worked to align periods and timeframes between our networks.

Time Periods	Peak	Shoulder	Off-Peak
Work days	07:00 – 09:30 17:30 – 20:00	09:30 – 17:30 20:00 – 22:00	22:00 – 07:00
Weekends and public holidays (incl. Northland regional holidays only)	No peak period	07:00-22:00	22:00 – 07:00

This pricing is mandatory for all residential and small to medium business consumers on DM1, DM3, DM7, ND1, and ND2, unless the consumer does not have a communicating smart meter, or the consumer's retailer is unable to provide time-sliced EIEP1 format data to facilitate time of use billing. If this is the case, the retailer may apply for an exemption setting out the reasons they cannot provide the data and steps they are taking to address this.

The differential between peak, shoulder, and off-peak has been set at a very low level for 2020-2021, but will be gradually increased over a five year period. This approach has been taken to mitigate the impact upon consumers (in the event that retailers choose to pass the changes through), giving consumers time to respond to the pricing structure and adapt their behaviours, while also signalling what changes will be made in coming years.

3.4 Residential Standard Plan

The Low Fixed Charge Regulations require us to offer a residential plan for consumers at their permanent place of residence, where the daily charge is no more than 15c per day (excluding GST). We may also offer a standard residential plan for consumers at their permanent place of residence with a different daily charge, provided that the charges under both plans are the same at 8,000kWh p.a.

To improve the cost reflectiveness of our pricing within the constraints of the Low Fixed Charge Regulations, we have this year introduced a standard residential plan for consumers at their permanent place of residence. Residential connections using over 8,000kWh a year will be able to move to this plan which will have a higher daily price and a lower per kWh price, better reflecting their fair share of the fixed costs of running our network.

This pricing will encourage more efficient use of the network, given it has spare capacity at certain times which can be utilised at little to no incremental cost.

The average residential connection which uses over 8,000kWh p.a. is forecast to pay 9% less in annual lines charges by changing to the standard residential plan. We encourage all consumers to check with their retailers that they are on the best plan for them.

We are forecasting an average 46,380 permanent place of residence connections in 2020-2021, representing 78% of our total forecast ICPs. Of the 46,380 ICPs, we have forecast that 12,102 or 26% of connections will use more than 8,000kWh p.a. and could benefit from moving to the new DM7 price category code. 34,277 are forecast to use less than 8,000kWh, which is 74% of total permanent place of residence connections and 57% of total connections.

3.5 Rebalance fixed and variable prices

The majority of our costs are fixed in nature, meaning that they do not vary based on how much electricity our consumers use. This reflects the physical nature of our network, which is primarily made up of power poles, power lines, transformers, and substations. Investments to extend the network, replace assets, or create more capacity are made with a long term view of usually 40 years plus.

We are changing our pricing over time to better reflect the fixed cost nature of our business and to incentivise consumers to shift usage to times where there is spare capacity in the network. This has a number of benefits, including sharing the cost of the network more fairly across those who have access to the network, reducing the incremental cost to consume electricity, and reducing revenue risk. It also addresses the impact of flat to falling electricity consumption per connection, which is driven by consumers investing in more efficient appliances, and installing distributed generation and storage such as solar and batteries.

As part of this, we have this year increased the daily price for a number of price categories, and in most cases reduced the per kWh prices. We plan to continue to rebalance fixed and variable pricing over a 5 year period commencing from 2020-2021, to achieve a cost reflective outcome (within the constraints of the Low Fixed Charge Regulations which impose limits upon daily charges for some residential consumers).

3.6 Roadmap

We have prepared and published a roadmap outlining our plan to implement cost reflective pricing, and update it with our progress every six months. It is available on our website. This year we have implemented Time of Use for residential and small to medium business connections and continued reweighting fixed and variable charges. For the next 12 months our focus will be on:

- Reviewing large commercial and industrial consumer pricing structures
- Bedding in and further improving Time of Use pricing for residential and small to medium businesses, including considering any transition required if the Low Fixed Charges Regulations are repealed by the Government.
- Reviewing distributed generation pricing structures

We will also be looking at how we can incorporate economic costs and increase the number of consumer groups in our Cost of Supply model, noting that resulting changes in pricing will be phased to mitigate impact on consumers and therefore are likely to affect the end point prices we reach in five years rather than be seen immediately in 2021-2022.

4 Changes to Pricing Methodology in 2020-2021

We have made some changes to our pricing methodology for 2020-2021. This is the way that we allocate our costs across the price categories that we offer:

- We have combined the Mass Market and ND9 consumer groups, because these consumers mostly use the same shared assets. We plan to review the structure of our consumer groups this year, with a view to increasing the number of consumer groups in 2021-2022.
- We have updated some of the cost allocators, to better reflect the cost drivers of the costs.
- As discussed above, we have introduced Time of Use pricing structures as mandatory for all residential and small to medium business consumers, with a default plan available for retailers who cannot meet the data requirements. The pricing between the Time of Use plans and the Default plans is set to be revenue neutral.

5 Target Revenue

We are targeting to recover $71.9m through prices for the year ending 31 March 2021, which covers the following components. These costs are forecast to be incurred to operate and maintain the electricity network.

Type	Component	2020 $m	2021 $m
Distribution	Operating Expenditure	25.2	27.0
	Depreciation	10.0	11.2
	Regulatory Tax Allowance	3.9	3.3
	Revaluations	(5.3)	(5.4)
	Other Regulated Income	(0.5)	(0.4)
	Return on Investment	18.4	17.5
Pass through	Transmission	20.0	18.4
	Rates	0.1	0.1
	Levies	0.2	0.2
Total		**72.0**	**71.9**

The target revenue is ($0.1m) down on both FY19 and FY20.

6 Consumer Groups

We have categorised connections to our network into two groups, in order to allocate the target revenue to these groups as part of the price setting process. The groups have been developed based on the nature of the service that they receive and whether they use assets dedicated to their supply.

Consumer Group	Description
VLI	Very Large Industrial ("VLI") consumers have significant Northpower assets dedicated to their site. In most cases they have a dedicated feeder supplying their site from a Northpower substation, and often have dedicated backup feeders to provide N-1 security. They receive a higher level of service reflecting their reliance on electricity to operate significant sized and often critical industrial processes.
Mass Market	Mass Market includes all other sites including homes and businesses. These sites are supplied via assets which are shared across many consumers, and generally have no or very limited assets assets dedicated to their supply.

Customers are allocated to the above groups based on their method of connection to the network (i.e. consumers with dedicated feeders or significant Northpower assets are allocated to VLI) and reflected by their price category code. The allocations are made in consultation with the consumer or retailer usually based on their request, to balance consumer and network outcomes.

7 Allocation of Target Revenue to Consumer Groups

We use our Cost of Supply model ("CoS model") to allocate the costs of owning and operating the distribution network to the consumer groups described in the previous section, to determine how much of the target revenue we intend to recover from each consumer group. The allocators reflect how the different consumer groups drive the cost components.

7.1 Transmission

Transmission is made up of Transpower's charges for access to the national grid, and Avoided Cost of Transmission ("ACOT"). ACOT is paid to generators who inject electricity directly into the Northpower network, and through doing so reduce the charges that we would otherwise pay to Transpower.

Transpower's charges consist of two costs, 'interconnection' and 'connection'. Interconnection represents our contribution to the National Grid, and connection is the charges for assets located at the Grid Exit Point through which we connect to the National Grid.

Interconnection

Our contribution to the National Grid is charged by Transpower based on our share of the total load in the Upper North Island during the 100 half hour periods with the highest load for the prior 12-month period. We calculate the load of the different consumer groups during the same half hour periods to allocate the Transpower interconnection cost.

We also pay ACOT to eligible generators who inject into the Northpower network during the 100 highest peaks, calculated as the amount that we would have otherwise paid to Transpower. ACOT expenses are allocated to the consumer groups using the same methodology as Interconnection, and are included in the table below.

Consumer Group	Contribution to RCPD (kW)	%	Cost ($m)
VLI	58,370	36%	5.7
Mass Market	105,549	64%	10.4
Total	**163,909**	**100%**	**16.1**

Connection

Transpower also charges us for our share of the costs for the grid exit points ("GXPs") that we use, based on the value of the assets and our usage of those assets. These are allocated to the consumer groups based on their contribution to the peak demand at each GXP, calculated as the average of the 12 highest half hour periods for the Capacity Measurement Period (for 2020/2021 pricing, the period from September 2018 to August 2019).

Consumer Group	Contribution to peak demand (kW)	%	Cost ($m)
VLI	73,214	43%	1.5
Mass Market	98,602	57%	0.8
Total	**171,816**	**100%**	**2.3**

We connect to Transpower's national grid at three different GXPs; Bream Bay, Maungatapere, and Maungaturoto. The costs of each GXP have been attributed separately to each consumer group, and then added together. As such, the percentage of a consumers group's contribution to peak demand may vary from the percentage of cost allocated to them.

7.2 Operating Expenditure

Asset Costs

The costs to maintain and repair network assets are allocated to consumer groups based on the degree to which each of the consumer groups use or have access to the underlying assets. Assets have been allocated using the allocators below:

Asset	Allocator	VLI	Mass Market
Dedicated sub-trans mission (33kV) lines/ cables	Customer allocation	100%	0%
Sub-transmission (33kV) lines/cables	Peak demand	3.7%	96.3%
Zone substations	Peak demand	17.5%	82.5%
Distribution (11kV) lines/cables	Length	0.0%	100.0%
Distribution substations and transformers	kVA	2.4%	97.6%
LV (400v) lines/cables	Length	0.0%	100.0%
Distribution switchgear	Peak demand	17.5%	82.5%
Other network assets	Assessment	0.0%	100.0%
Non-network assets	Assessment	5.0%	95.0%
Weighted Total	**Asset Value**	**4.59%**	**95.7%**

Preventative maintenance is allocated based on the weighted total value of assets utilised by the consumer group, as all assets require periodic maintenance. Reactive maintenance (i.e. fault call outs) are primarily driven by incidents which affect power lines and poles (for example trees falling on lines, cars hitting poles, diggers hitting buried cables) and as such reactive maintenance is allocated based upon line/cable length.

Operational costs relating to running and maintaining the core assets in our network are allocated based on the cost allocator assigned to the asset type they support. For example, substation related running costs are assigned based on peak demand, which is also used to allocate substation asset costs.

Non Asset Costs

Non Asset costs are the overhead costs to operate and maintain the network. They include the engineers who monitor the performance of the network, design extensions and upgrades, and plan for the future. It also includes the customer services teams, operations teams who monitor the network 24/7 and manage outages, health and safety, and billing functions. We allocate these costs based on an estimate of the proportion of total resources that each consumer group utilises.

Return on Investment, Depreciation, Regulatory Tax Allowance, and Revaluations

These costs are where we recover the depreciation on the assets which make up our network, the cost of tax, and a return on our investment. This component is important because it allows us to replace assets as they reach the end of their lives, and to invest in new assets as the network expands, new technology, and improve the performance and reliability of the network.

These costs relate to the underlying network assets, and are therefore allocated to the consumer groups based on the total assets that each consumer group uses as described above.

7.3 Total Target Revenue allocated to each Consumer Group

Using the allocators described above, we allocate the $71.9m target revenue to each of the consumer groups. The target amount that we intend to recover from each group is outlined below:

	Component	VLI $m	Mass Market $m	Total $m
Distribution	Operating Expenditure	1.4	25.6	27.0
	Depreciation	0.5	10.7	11.2
	Regulatory Tax Allowance	0.2	3.1	3.3
	Revaluations	(0.2)	(5.1)	(5.4)
	Other Regulated Income	0.0	(0.4)	(0.4)
	Return on Investment	0.8	16.7	17.5
Pass through	Transmission	7.2	11.2	18.4
	Rates	0.0	0.1	0.1
	Levies	0.1	0.1	0.2
Total		**9.9**	**61.9**	**71.9**

8 Price Setting Process

The following sections explain how we set our prices to recover the Target Revenue allocated to each consumer group. It explains what types of prices are used, and how the prices are set.

Types of Prices

The types of prices used across our price categories are described below. Only some of these components apply to each price category.

Price Component	Units	Description
Daily price	$/day	Daily price is applied to the number of days each ICP is connected to our network.
Monthly price	$/month	Monthly price is applied to the number of months each ICP is connected to our network.
Volume	$/kWh	Volume price applied to the volume of electricity distributed to each ICP. The rate may vary depending on the price category, for example uncontrolled (available 24 hours a day), controlled 18 (available 18 hours a day), or controlled 22 (available 22 hours a day).
Anytime maximum demand	$/kVA/ month	Anytime maximum demand is the highest half-hour demand at any time each year. It is initially charged based on the prior year, and then subject to a ratchet adjustment during the year based on actuals including a washup back to the start of the year. A year end washup applies if the actual anytime maximum demand does not exceed the prior year.
Network Peak Period demand	$/kVA/ month	Network Peak Period Demand is the consumer's peak demand between 0700 – 1000 and 1700-2130 from May to September, which reflects the peak periods on our network and generally coincides with the UNI regional peaks. It is calculated as the average of the 6 highest half hour periods. It is initially charged based on the prior year, and then subject to a ratchet adjustment during the year based on actuals including a washup back to the start of the year. A year end washup applies if the actual anytime maximum demand does not exceed the prior year.
Excess Reactive Power	$/excess kVAr/ month	Where the power factor falls below 0.95 lagging for the highest half hourly demand in a month, the excess kVAr is charged.

8.1 Mass Market

We have a number of Mass Market price categories to comply with regulations and meet the needs of different groups of consumers.
For residential and small to medium business plans we have a ToU plan, and a default option which applies when the customer does not have a communicating smart meter or the retailer has a valid approved exemption.

Consumer Group Subset	Price Category Code	Description
Residential	DM1 DM1-ToU	Residential Low User – Principal Place of Residence
	DM3 DM3-ToU	Residential - Non Principal Place of Residence
	DM7 DM7-ToU	Residential Standard - Principal Place of Residence
General	ND1 ND1-ToU	Up to 70kVA - 100A or less
	ND2 ND2-ToU	Greater than 70kVA (CT metering)
	ND5	Irrigation and pumps
	ND6	Unmetered 24 Hour
	ND12	Builders Temporary Supply
Streetlights	H	Daily Price
	26-1	Demand band 1
	26-2	Demand band 2
	26-3	Demand band 3
	26-4	Demand band 4
	26-5	Demand band 5
Large Commercial & Industrial	ND9	Demand Based Pricing
	ND10	Volume Based Pricing

Our process to set prices is to forecast the expected volumes for each price category and component, and adjust the prices to achieve our Mass Market revenue target of $61.9m. Our pricing strategy informs our approach to making these changes.

The key changes for this year are to:

- Introduce ToU price plans for DM1, DM7, DM3, ND1, and ND2 as we roll out cost reflective pricing.
- Introduce a Standard Residential plan (DM7) for residential permanent place of residence consumers using more than 8,000kWh p.a.
- Increase the daily price for some plans, and in most cases to reduce the variable prices, to better reflect the fixed cost nature of our cost base.
- Remove the DM4 and DM6 plans as we simplify our pricing structure

The Low Fixed Charge Regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option equals any other primary price of residence price option for residential consumers using 8,000kWh per annum. Our DM1 and DM7 price categories comply with these regulations.

Some Mass Market prices have changed compared to the prior year due to reduced target revenue for this consumer group ($0.9m) and the balance are due to the implementation of cost reflective pricing structures outlined above.

8.2 Very Large Industrial

We offer non-standard pricing to very large industrial consumers who would like us to own and operate assets of significant value which are dedicated to their supply. We currently have six consumers in this consumer group, of whom one has a non-standard contract and five operate under their retailer's Use of System Agreement. Consumers in this group can choose if they want to be on a non-standard contract or billed via a retailer.

The pricing is based on the assets that the customer uses and the services that they receive, to ensure Northpower recovers the costs of the dedicated and shared assets, an appropriate return on investment, and the associated operating and maintenance costs. Transmission costs are passed through in a transparent manner.

The revenue target for these consumers is $9.9m for 2020-2021. We forecast that revenue from these consumers will be $9.6m, primarily due to our contracts with one customer which limit our revenue to less than the cost reflective target revenue. This arrangement is of a long term nature and was agreed prior to the implementation of the current regulatory regime.

VLI prices have changed compared to the prior year due to increased target revenue of $0.8m.

8.3 Distributed Generation

We do not currently charge distributed generators to use our network to convey electricity to their customers. In the event that costs are incurred to connect a generator to the network, we will look to recover those costs.

We pay ACOT of $1.2m to two large scale generators under Part 6 of the Electricity Industry Participation Code. This involves assessing the generator's average output at the time of the 100 highest UNI peaks, to calculate the Transpower interconnection cost saved due to the generator injecting into our network at the time of those peaks.

We do not pay ACOT to owners of small scale generators below 10kWh, as most small scale generation is solar and therefore the generation is unlikely to coincide with the UNI 100 highest peaks and reduce the Transpower transmission cost as a result.

9 Responsibilities to Very Large Industrial consumers

While only one of our VLI consumers is on a non-standard contract, our obligations and responsibilities to that consumer are broadly the same as other consumers including VLI consumers. The key difference is that VLI consumers including those on non-standard contracts are able to input into their supply configuration, and as such they sometimes opt to duplicate assets to increase security of supply. For example, some VLI sites elect to have two incoming feeders, each capable of supplying the entire load for the site, to ensure they have a backup if one feeder fails. They also often have assets which are dedicated to their supply, such as dedicated feeders.

The non-standard pricing offered to our VLI consumers reflects the assets which they use, and as such their contribution towards target revenue covers the additional cost of the duplication of assets to improve security of supply.

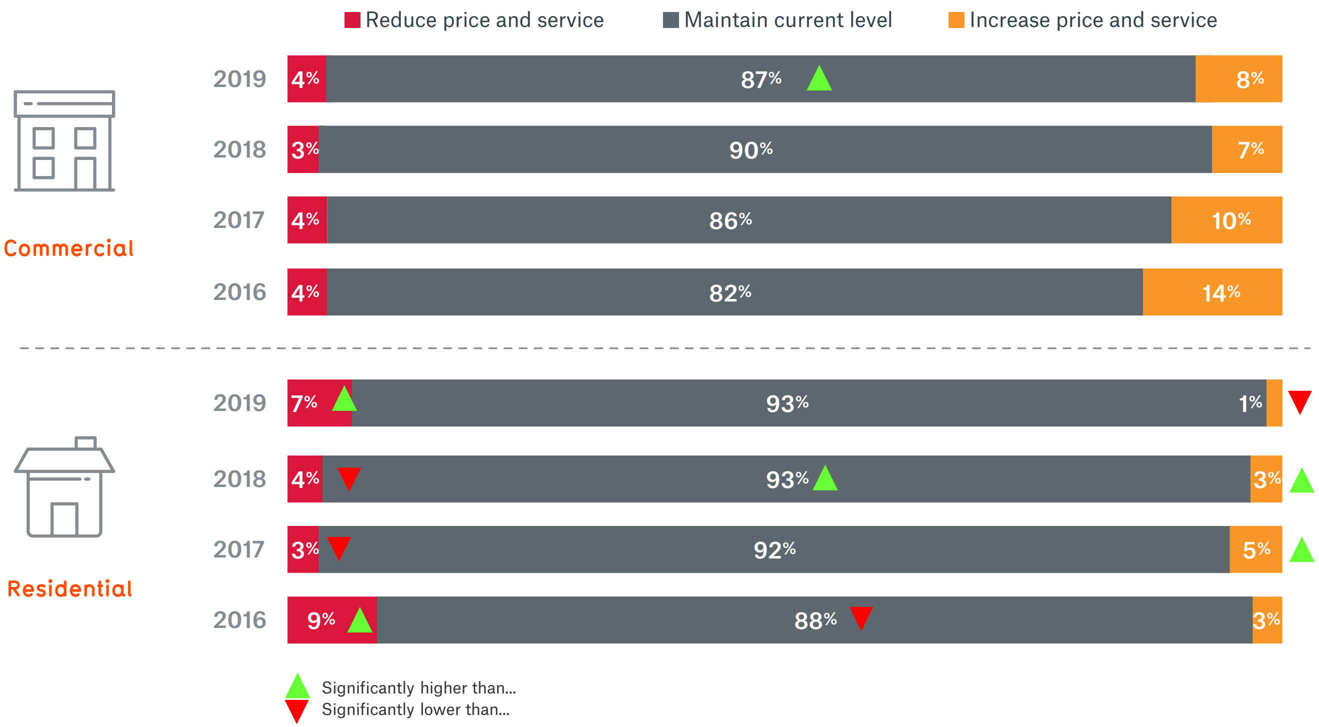
10 Consultation

We consult with a range of stakeholders including consumers, retailers, and the Northpower Electric Power Trust on behalf of our consumer owners, on a range of issues including their views on pricing, quality, and the desirable level of trade-off between these two factors. For example, the below question is from our 2019 annual survey of consumers.

The majority of consumers are satisfied with the current levels of service and would prefer that these are maintained rather than the price level adjusted. We factor these views into our expenditure planning, which flow into our target revenue and ultimately prices.

We consulted extensively with retailers on the changes made to 2020-2021 pricing, and in particular on the introduction of ToU pricing for residential and small to business businesses.

Preferred Level of Service (1)(2)



NOTES:

1. *Sample: 2016 Total n=400, Commercial n=100, Residential n=300; 2017 Total n=400, Commercial n=100, Residential n=300; ;2018 Total n=400, Commercial n=100, Residential n=300; 2019 Total n=403, Commercial n=101, Residential n=302*
2. *CP3. Northpower's level of service is based on reliability of supply, supply quality such as avoiding surges and spikes, and response times to faults. Changes in service levels might require changes in price. If you had to choose which one of the following best describes what you prefer?*

Appendix 1: Proportion of Target Revenue by Price Component

Price Component	Price Component Code	%
Mass Market		
General daily price	A, P	6.9%
Large Commercial daily price	B	0.7%
Principal place of residence daily price (low user)	C	2.6%
Principal place of residence daily price (standard user)	K	3.0%
Non-principal residence daily price	W	1.8%
Builders Temporary Supply daily price	T	0.3%
Residential Uncontrolled (low user)	2	3.3%
Residential Uncontrolled (standard user)	4	2.5%
All-inclusive (Obsolete)	71	0.0%
Non-principal Residence Uncontrolled	3	0.2%
General Uncontrolled	33, 43	4.2%
Large Commercial Uncontrolled	32	1.3%
Metered lighting	19	0.0%
Unmetered lighting	24	0.0%
Builders Temporary Supply Uncontrolled	53	0.1%
Controlled 18 hour	06, 46	4.8%
Controlled 22 hour	05, 55	2.7%
Night only	07, 47, 1207	0.1%
Controlled day	11	0.2%
Controlled night	12	0.0%
Daily price per unmetered installation	G	0.1%
Unmetered Uncontrolled	25	0.0%
Daily price per unmetered light fitting	H	0.9%
Half-hour metered volume-based daily price	J	0.2%
Half-hour metered volume-based	31	2.7%

Price Component	Price Component Code	%
Peak	1050, 1250, 1150, 1350, 1450	9.0%
Shoulder	1051, 1251, 1151, 1351, 1451	16.1%
Off-peak	1052, 1252, 1152, 1352, 1452	16.8%
ND9		
Demand-based prices	9	6.0%
Very Large Industrial		
Non-standard pricing	IND	13.5%
Total		100%

Appendix 2: Glossary

Term	Definition
AMD	Anytime Maximum Demand. The highest half-hour demand, usually in kVA, during a one year period.
Avoided Cost of Transmission ("ACOT")	A reduction in the transmission costs payable by distributors to Transpower (usually in the context of embedded generation).
Code	Electricity Industry Participation Code 2010 and subsequent amendments.
Commission	Commerce Commission
Consumer	A person or an entity whose electricity installation is connected to the electricity network.
Consumer Group	A broad category of electricity consumers.
Controlled	An option where consumers elect to have part of their electricity supply subject to interruption at Northpower's discretion. The most common example is control of electrically heated hot water.
Demand	Electricity load, measured in either kW or kVA, usually averaged over a half-hour period.
Distributor (EDB)	An entity other than Transpower which owns an electricity network other than an embedded network. Often denoted as an Electricity Distribution Business (EDB).
Distributed generation (DG)	An electricity generator connected directly to an electricity distribution network (rather than to the transmission grid). Also called Embedded Generation.
EDIDD	Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission as Decision NZCC 22 dated 1 October 2012, as subsequently amended.
Electricity Industry Act (EIA)	Electricity Industry Act 2010.
Half-hour metered	An ICP with metering that records electricity consumption in half-hour intervals.
ICP	Installation Control Point. An individual connection to an electricity distribution network.
kVA	Kilovolt-amp. Measure of total apparent power.
kVAr	Reactive power.
kW	Kilowatt. Measure of true power.

Appendix 2: Glossary

Term	Definition
kWh	Kilowatt-hour. Rate of energy flow.
Low Fixed Charge Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-principal place of residence	A residential premise that is not the principal place of the consumer in the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-standard contract	A contract that is not a standard contract in terms of the EDIDD 2012. (Refer to definition of Standard contract below.)
Point of Connection (PoC)	The connection between the transmission grid and a distribution network. Also called a Grid Exit Point (GXP).
Power factor	kW/kVA
Pricing Principles	The distribution pricing principles published by the former Electricity Commission in 2010, adopted by the Electricity Authority, and amended from time to time.
Principal Place of Residence	In the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Regional Coincident Peak Demand (RCPD)	The average demand at the times of the hundred highest half-hour regional demands.
Residential Consumer	A consumer at a residential ICP which satisfies the definition of "domestic premises" in Section 5 of the Electricity Industry Act 2010.
Standard contract	EDIDD 2012 defines a standard contract as one where the price for electricity line services is determined solely by reference to a publicly disclosed schedule of prescribed terms and conditions, or a contract which covers at least five persons, none of which is a related party to the EDB or each other.
TPM	Transmission Pricing Methodology – the methodology defined in accordance with Part F (subpart 4) of the Code by which transmission prices are allocated to participants with connections to the national electricity grid.
Transmission grid	The national electricity grid owned and operated by Transpower.
Upper North Island (UNI)	The area of the North Island north of Huntly.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
(a) Prices are to signal the economic costs of service provision, including by: i. being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs); ii. reflecting the impacts of network use on economic costs; iii. reflecting differences in network service provided to (or by) consumers; and iv. encouraging efficient network alternatives.	Our approach to setting prices is: 1. we allocate the costs of providing our services to consumer groups, based on the assets which are dedicated to them, the degree to which they share common assets, and the degree to which they drive the costs we incur to run the network. 2. we set prices for the consumer groups to signal the cost of providing that service. This approach does not yet include economic costs, but we are working to incorporate these and they will inform the end prices that we get to as we phase pricing changes over a five year period. This approach has been taken to mitigate the impact on consumers. **Subsidy free** The costs that we incur can be categorised as: • **Incremental costs:** these are costs incurred specifically for that customer, for example the cost of dedicated feeders for a VLI consumer. • **Shared costs:** these are costs which would still be incurred if any consumer group existed on a standalone basis, but when multiple consumer groups exist these costs can be shared. To be subsidy free, our forecast revenue for each consumer group should fall between avoidable costs (i.e. incremental costs) and standalone costs (incremental plus the full shared costs). We are forecasting to recover our incremental costs plus a portion of the shared costs from each consumer group, and therefore our pricing meets the subsidy free test in the Distribution Pricing Practice Note. **Reflecting the impacts of network use on economic costs** Northpower's costs are largely fixed, driven by the physical footprint of the network, and long term nature of investment decisions. Variable costs are largely limited to the Transpower transmission charges. ***Mass Market*** Our Mass Market pricing has historically had a high per kWh rate and low daily connection rate, which does not correlate closely to our costs drivers. To address this we have: • Introduced Time of Use pricing for residential and small to medium business from the 2020-2021 pricing year, enabling us in the future to vary our price by time of day to reflect congestion on the network, and incentivise consumers to shift load to avoid upgrade costs. Differential in peak, shoulder, and off-peak prices will be ramped up over multiple years to mitigate the impact on consumers. • Continued progressively rebalancing our fixed and variable prices, within the limitations of the Low Fixed Charge Regulations. Rebalancing will be completed over multiple years to mitigate the impact on consumers. • Introduced a Standard Residential plan so that we will have residential pricing options which are more cost reflective while still complying with the Low Fixed Charge Regulations.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
	These changes will over time address subsidies inherent in our historic pricing structures, such as between peak and off peak users, and low and high consumers of electricity from the grid. We will further be reviewing our ND9 and ND10 price category codes this year with a view to making these plans more simple, easy to understand, and cost reflective. While we have not specifically addressed density and distance from the GXP through location pricing due to complexity and transaction costs, we note that these are to some extent inherently reflected in our price category codes. For example, business prices on our network tend to be higher than residential because of the large number of farms which are further from the GXP and in less populated areas. Another example is our non-principal place of residence dwellings plan, which caters for holiday homes which also tend to be in less populated areas further from the GXP. ***Very Large Industrial*** Our pricing for VLI consumers is set based on the costs allocated to them, and therefore there is a direct correlation between their prices and our cost to provide the service to them. If they vary the service they require or the way they use our network, and this changes our costs, this has a direct impact on their costs. For example, the transmission costs, and the costs of assets dedicated to their supply, are passed through directly. Costs of shared assets and network management costs are passed through based on an appropriate cost driver. We note there is one VLI consumer for whom our pricing is limited by a non-standard contract that was struck prior to the implementation of the current regulatory regime. **Differences in network services** ***Mass Market*** Our Mass Market price category codes reflect the service that consumers receive: • We have different pricing depending on the capacity of the customer's connection to the network, as this is a key cost driver for us. • We offer lower per kWh rates for supplies where the consumer agrees that we may control the load for a period during the day to manage load on the network. For us this predominantly relates to hot water load control, and most residential dwellings in our network that have electric hot water have a ripple controller installed. These consumers receive a discount in relation to their controlled load, reflecting the lower availability level, and the benefit to us to be able to shift this load to reduce costs and network investment.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
	VLI Our VLI pricing is a direct charge through of the costs we incur to provide them with the service, as such it inherently reflects the differences in the service they receive. For example, most VLI consumers have dedicated feeders, some with N-1 security. The costs of the assets are charged back to them, reflecting the differentiated service they receive in terms of dedicated assets and increased security of supply. These consumers also receive a higher level of personalised service compared to the average consumer. For example, they have direct access to our 24/7 control room in the event of an outage, receiving direct updates, control room to control room coordination, and priority restoration. Another example is that we liaise around Northpower and Transpower maintenance schedules to avoid their busy periods and where possible to coincide with planned maintenance windows. Their pricing reflects this higher level of personalised service. **Encouraging efficient network alternatives** ***Distributed Generation/Storage*** We think that the current risk from our pricing is not that it doesn't do enough to encourage efficient network alternatives, but that in some scenarios it may subsidise inefficient network alternatives. This is largely driven by the Low Fixed Charge Regulations, which limit the daily connection charges that we can charge for most connections on our network to levels well below cost. If a network prices its daily connection prices below its actual fixed costs to connect a consumer to the network, and recoups the balance of its fixed costs through variable charges, this creates an incentive for the consumer to invest in distributed generation and distributed storage to reduce their variable charges. The result is that the network receives less in revenues than its costs to provide the connection, and other consumers have to pay the shortfall through their variable charges. It also means that the electricity network is under-utilised, whilst the consumer has purchased equipment to duplicate the electricity network functions, which is inefficient. We are rebalancing our fixed and variable prices to address this (within the limitations of the Low Fixed Charge Regulations). Whilst the rebalancing will take place over a number of years to mitigate the impact on consumers, we are also signalling the changes to consumers so that they can make educated decisions to invest in network alternatives. ***Demand Response/Interuptible demand*** As described above, we offer discounted pricing for controlled load and have also this year introduced Time of Use pricing. These price signals will over time incentivise consumers to shift load and adjust their demand at certain times of the day when we might experience congestion, in order to avoid investment in transmission or distribution upgrades.
(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.	Our cost allocation does not currently include economic costs such as marginal cost of supply, or costs that need to be signalled but are not borne by distributors. As such there is no shortfall to be made up. As described above, we will be working to incorporate these costs into our Cost of Service model and will be gradually phasing our pricing to reach its cost reflective end point over five years to mitigate the impact on consumers.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	Consistency of Northpower pricing methodology
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: i. reflect the economic value of services; and ii. enable price/quality trade-offs.	**Reflect the economic value of services** Our VLI consumers are able to negotiate directly with us to achieve prices which are cost reflective and fair to both parties, and as such are unlikely to curtail demand, disconnect, or not connect due to facing standard prices. Mass Market consumers often currently receive lower daily and higher variable prices which incentivise them to inefficiently curtail demand, for example by acquiring further electrical assets to construct distributed generation or storage. We are phasing in prices to send appropriate signals regarding this over a period of time. For larger consumers who might disconnect or not connect in the first place if faced with standard pricing, we offer capacity based charging which reflects the service they receive. **Price/quality trade offs** Our VLI consumers have individually negotiated arrangements, where they can determine the various service quality aspects of their connection and their pricing is adjusted accordingly based on the cost to us to provide that service. For example, some VLI consumers opt to have dedicated feeders so they have guaranteed capacity, to underground their feeders to increase security of supply, and to have multiple feeders to provide N-1 security. Some opt to connect at 33kV and provide their own transformers, whilst others opt for Northpower to provide and maintain transformers. It is practically difficult to provide Mass Market consumers with options to vary their level of service quality (reliability, resilience, etc) at an individual or price plan level, as they are using shared assets. However our pricing does, where practical, include options which relate to service quality, for example consumers can opt for a controlled 18 hour or night only price plan where they receive a lower price in exchange for reduced availiabity of supply. We are seeing electric vehicle owners in particular take advantage of lower priced electricity in exchange for reducing their availability hours, in addition to the usual hot water load control. We do survey consumers to understand their views on price, service levels, and the trade-off between these factors. This is factored into our price setting processes.
(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.	**Transparency** Our development of pricing is transparent, in that we describe our approach and the strategic changes we are making to pricing in our Pricing Methodology. We will this year also publish shorter messaging outlining the changes in pricing for this year, and how we expect our prices to change in coming years. This messaging will focus on expected outcomes rather than the methodology, so that consumers can quickly and easily understand the future landscape so they can make informed decisions when making long-lived investment decisions. **Transaction costs, consumer impacts, and uptake incentives** Our pricing is not yet perfectly cost reflective, because we are phasing price changes over a number of years in order to mitigate the impact on consumers. We have also made some decisions to not be perfectly cost reflective, for example: • We have aligned our Peak, Shoulder, and Off Peak time periods with Top Energy to create one standard pricing structure for residential and small to medium business across Northland. While this is not perfectly cost reflective as we have slightly different peaks, it mitigates the impact on and creates efficiencies for retailers. • We have not implemented locational pricing as we consider the transaction costs outweigh the benefits.

Schedule 17: Certification for Year-beginning Disclosures

(Distribution Pricing Methodology for the year commencing 1 April 2020)

Clause 2.9.1

We, **Nikki Davies-Colley** and **Mark Trigg**, being Directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1 to 2.4.5 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.

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Date: 3 March 2020

Northpower