Northpower

Distribution Pricing Methodology Disclosure

Applicable from 1st April 2017 until 31 March 2018

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1 Purpose

This document describes the methodology used by Northpower to determine the distribution pricing for connections to the Northpower electricity distribution network in accordance with the requirements of Section 2.4 of the Electricity Distribution Information Disclosure Determination (EDIDD) 2012 as consolidated in 2015. The 2012 EDIDD superseded the previous 2004 and 2008 disclosure requirements.

The Commerce Commission's EDIDD 2012 includes a requirement to demonstrate the extent to which the pricing methodology is consistent with the Electricity Authority's Pricing Principles and this is covered in Appendix 3 of this document.

Northpower uses an "interposed" arrangement where the electricity retailers are contractually interposed between the electricity distributor (Northpower) and the end-use consumers. As such, Northpower invoices the electricity retailers for the distribution prices applicable for each connection to the Northpower network and the retailers invoice the end-use consumers for the energy costs plus the distribution costs. Retailers can "repackage" the distribution prices in whatever manner they choose, subject to certain requirements such as the Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004.

2 Legislative Background

Currently, as a consumer-owned electricity distributor, Northpower is deemed to be an exempt Electricity Lines Business and does not require a Default Price Path or a Customised Price Path but is required to comply with the Information Disclosure regime.

Northpower's distribution pricing is subject to various legislative frameworks as follows:

- Commerce Act 1986 (administered by the Commerce Commission);
- Electricity Distribution Information Disclosure Determination (EDIDD) 2012 (Commerce Commission);
- Distribution Pricing Principles and Information Disclosure Guidelines (Electricity Authority);
- Electricity Industry Participation Code (Electricity Authority); and
- Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004 (MBIE and Electricity Authority).

3 Transmission Pass-Through

The pass-through of transmission charges is a significant component of distribution pricing. Electricity distributors pay Transpower for the use of relevant local connection assets and they contribute to the cost of the interconnected grid in accordance with the Transmission Pricing Methodology (TPM). Distributors also pay owners of distributed generation for any Avoided Cost of Transmission (ACOT).

Distributors are required to allocate these transmission costs transparently to the consumer groups in a manner that ensures that the total cost is recovered without any mark-up. The current TPM sets transmission pricing for Connection charges on the basis of the values of the connection assets and it determines the Interconnection Charges on the basis of contributions to regional peak demand. Northpower currently

allocates the relevant share of the total transmission costs to each main consumer group on the basis of each group's contribution to the Regional Coincident Peak Demand (RCPD).

If the Electricity Authority proceeds with its plan to change the allocation methodology in the TPM from RCPD to Area-of-Benefit (AoB), then Northpower will need to change its allocation methodology to reflect that. However, the Electricity Authority has indicated that any changes to the TPM will not take effect until April 2021.

4 General Pricing Principles

Requirement 2.4.3(1) in the 2012 EDIDD

The general overarching principles utilised by Northpower when setting distribution prices are:

4.1 Fairly reflect the cost of supply to the main consumer groups

To the extent that is practical, Northpower's distribution prices reflect the cost of supply for each of the three main consumer groups (Very Large Industrial group, Commercial & Industrial (C&I) group and Mass-Market group).

While this is straightforward for some assets such as the 400V local distribution network which is utilised primarily by the Mass-Market group, many assets are shared – for example an 11kV distribution feeder supplying a supermarket (in the C&I group) in a suburban location would also supply the nearby houses (in the Mass-Market group).

The following table from the current Distribution Pricing Methodology disclosure document shows how the various types of distribution assets are allocated across the three main consumer groups.

Table 5 from Section 4 of this disclosure document - Distribution asset utilisation by the main consumer groups

Distribution assets	Used by Very Large Industrial?	Used by C&I?	Used by Mass Market?
Sub-transmission lines	Yes	Yes	Yes
Sub-transmission cables	Yes	Yes	Yes
Zone substations	Yes	Yes	Yes
HV + LV lines	One short HV line	HV, not LV	Yes
HV + LV cables	Negligible	HV, not LV	Yes
Distribution transformers	No	Yes	Yes
Distribution switchgear	No	Yes	Yes
Other network assets (Load control)	No	No	Yes
Non-network assets (Offices, etc)	Yes	Yes	Yes

Where distribution assets are assigned to more than one main consumer group, the portion assigned to each group is determined by Northpower's Cost of Supply model.

4.2 Encourage responsiveness

Northpower's distribution pricing for the Very Large Industrial and C&I sites is demand-based to encourage demand-side management.

Prices for controlled load for mass-market consumers are significantly lower than for uncontrolled load to provide incentives for consumers to make load available for control.

4.3 Facilitate long term pricing stability

Northpower endeavours to provide long term stability in its distribution pricing structures and to avoid price-shocks for consumers.

Northpower continues to monitor the impacts of new technologies and whether these warrant changes to current pricing methodologies including: changes in cost allocators, efficient signalling methodologies, or other fundamental drivers.

Any resulting changes to the pricing methodology will follow the appropriate consultation and approval processes.

4.4 Provide an appropriate rate of return

Northpower's principal objective is to operate a successful and sustainable business for the benefit of our shareholder. This includes earning a reasonable commercial rate of return on the distribution asset base to meet the operating costs of the network, to fund replacement of end-of-life capital assets and upgrading, and to cater for network growth.

5 Revenue Requirements

Northpower's distribution prices cover transmission costs, depreciation costs, maintenance costs, operational costs, administration costs and a return on distribution assets.

5.1 Target Revenue

Requirement 2.4.3(3) in the 2012 EDIDD

The total target revenue expected to be collected from distribution charges for the FY18 pricing year (1 April 2017 to 31 March 2018) is $70 million. This is comprised of $46 million from distribution revenue plus $24 million pass-through of transmission costs including payments to Transpower, ACOT (avoided cost of transmission) payments and acquired transmission assets.

In the previous year (1 April 2016 to 31 March 2017)(FY17) the total revenue target from distribution charges was $66 million, comprised of $44 million from distribution revenue plus $22 million pass-through of transmission costs.

5.2 Changes to prices effective from 1 April 2018

Requirement 2.4.3(6) in the 2012 EDIDD

5.2.1 Residential (domestic) group

The distribution portion of variable prices for principal places of residence will increase by 5%.

5.2.2 Changes to fixed prices

Daily prices for general (non-domestic) Mass-Market ICP's will increase from 85 cents to 100 cents per day, consistent with Northpower's distribution pricing strategy to increase the daily fixed price from 70 cents to 100 cents across a two year period (2016 and 2017).

The daily price for principal places of residence remains at 15 cents per day to comply with the Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004 (commonly referred to as the "Low Fixed Charge Regulations").

A new Price Category was introduced on 1 April 2015 for residential properties which are not principal places of residence. This has a higher daily price than the Price Categories for principal places of residence, as a move to more cost-reflective service-based pricing.

5.2.3 Transmission pass-through

Transmission charges and ACOT (Avoided Cost of Transmission) will continue to be passed through to the relevant consumer groups.

Transpower notified Northpower that the Interconnection Rate (which covers the cost of the interconnected grid) will increase by 8% from $114.47/kW pa in FY17 to $123.98/kW pa in the pricing year commencing 1 April 2017 (FY18). Connection Charges will increase by around 3%.

5.2.4 Alignment to the ENA Distribution Pricing Guidelines

Last year, Northpower aligned the terminology in its distribution price schedules with the recommendations in the Distribution Pricing Guidelines (DPG version 1.1) published by the Electricity Networks Association (ENA) in August 2015. Following the publication of version 2 of the DPG in 2016, further alignment has been undertaken.

6 Consumer Groups

Requirement 2.4.3(5(a) in the 2012 EDIDD

Connections to the Northpower network have been categorised into three main groupings on the basis of the range of asset utilisation (sub-transmission, 11kV distribution and 400V distribution). Sites range in consumption from over 200 GWh per annum, down to a few kWh per annum.

The groupings are as follows:

Very Large Industrial sites (Asset-based prices)

Sites supplied at 33kV, or supplied at 11kV on dedicated feeders from substations.

C&I (Commercial & Industrial) (Demand-based prices)

All sites with demand-based distribution prices, excluding the Very Large Industrial sites.

Mass-Market sites (consumption-based prices)

This group contains most of the connections to the network and includes households, commercial sites, farming operations and small industrial sites. It comprises all the ICP's with consumption-based distribution prices and unmetered ICP's.

Comparative statistics for the three Consumer Groups are shown in Tables 1 to 4 following:

Table 1 Consumer groups by number of ICP's

Group	Number of ICP's at 1 April 2015	Number of ICP's at 1 April 2016	Number of ICP's at 1 April 2017	Percentage
Very Large Industrial	6	6	6	0.01%
C&I	75	76	77	0.13%
Mass-Market	56,127	56,866	57,858	99.86%
Total ICP's	56,208	56,948	57,941	

Table 1 indicates the Very Large Industrial sites comprise only 0.01% of the number of ICP's. However, Table 2 below shows that the Very Large Industrial sites consume nearly 50% of the electricity transported through the Northpower network annually.

Table 2 Consumer groups by consumption

Group	2014/2015 (FY15) consumption	2015/2016 (FY16) consumption	2016/2017 (FY17) estimate	FY17 Percent
Very Large Industrial	463 GWh	491 GWh	525 GWh	49%
C&I	83 GWh	85 GWh	86 GWh	8%
Mass-Market	447 GWh	453 GWh	452 GWh	43%
Total consumption	993 GWh	1029 GWh	1063 GWh	

Table 3 following shows each consumer group's contributions to the regional peaks (but note that the percentages shown are the percentages of the Northpower contribution, not of the entire regional peak). Comparison of the percentages of consumption versus the percentages of peak load shows that the load factors for the Very Large Industrials are higher than for the Mass-Market group.

Table 3 Contributions to peak regional demands to August 2016 (for FY17 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at times of RCPD	58,874	36%
C&I	Sum of Network Peak Period demands x 60%	12,106	7%
Mass-Market	Residual	92,068	56%
RCPD + generation		163,048	100%

The 60% factor used in the C&I group was derived by analysis of the half-hour data for the largest C&I consumers at the times of the RCPD periods compared to their Network Peak Period demands.

The average of the highest hundred regional highest demands from the Capacity Measurement Period (CMP) from September 2015 to August 2016 was used by Transpower to set the Interconnection Charges for the year commencing 1 April 2017. This was the first year that averaging over a hundred highest demands was applied in the Upper North Island (UNI). Previously the averaging was over the twelve highest regional demands.

Table 4 following shows each consumer group's contribution to the highest GXP peaks. Note that the loads at the GXP's tend to peak at different times, so the sum of the non-coincident GXP peaks is higher than the total

system demand at any one time. A factor of 60% has been applied to the sum of the C&I group's Network Peak Period demands to allow for load diversity between the individual sites.

Table 4 Contribution to GXP peak demands in 2016 (for FY18 pricing)

Group	Allocator	Contribution to GXP demands	Percent
Very Large Industrial	Actual demands at GXP peaks	67,663	40%
C&I	Sum of Network Peak Period Demands x 60%	12,106	7%
Mass-Market	Residual	89,565	53%
	Sum of averages of 12 highest GXP demands	**169,334**	**100%**

7 Determination of the appropriate Consumer Group

Requirement 2.4.3(5)(b) in the 2012 EDIDD

The methodology for allocating each connection to the appropriate consumer group is:

7.1 Very Large Industrial sites

Sites which are very large by the sheer scale of their operation, or which have significant Northpower network assets dedicated to their electricity supply from the grid connection substation to the site. These sites are supplied directly from the sub-transmission system (33kV) or, in one case, via a dedicated 11kV distribution feeder from a zone substation.

7.2 C&I (Commercial & Industrial) sites

Connections for large commercial and industrial consumers supplied by dedicated on-site distribution transformers exceeding 150kVA are generally allocated to this group but there are some which are supplied directly from large transformers in the CBD which are shared with other consumers (for example: an 800kVA transformer supplying a multi-tenanted commercial building with several ICP's.) The group includes supermarkets, large sawmills, large quarrying operations, large pumping stations and some commercial sites.

7.3 Mass-Market

The remaining connections for small businesses, farming and residential consumers, including all unmetered connections.

8 Allocation of Network Asset costs to Consumer Groups

Requirement 2.4.3(1) in the 2012 EDIDD

The general principles are as follows:

Sub-transmission system
Dedicated assets are allocated directly to the relevant consumer group and shared assets are allocated on the basis of the relative demand from each group.

HV distribution

Apart from a dedicated 11kV feeder supplying one Very Large Industrial site, costs associated with the 11kV distribution system are shared between the C&I and the Mass-Market groups.

LV Distribution

All costs associated with 400V local distribution are allocated to the Mass-Market group.

In terms of the categories used in Schedule 4 of the Information Disclosure of the Regulated Asset Base (RAB), the utilisation by each of the three Consumer Groups is as follows:

Table 5 Distribution asset utilisation by consumer group

Distribution assets	Used by Very Large Industrial?	Used by C&I?	Used by Mass Market?
Sub-transmission lines	Yes	Yes	Yes
Sub-transmission cables	Yes	Yes	Yes
Zone substations	Yes	Yes	Yes
HV + LV lines	One short line	HV, not LV	Yes
HV + LV cables	Negligible	HV, not LV	Yes
Distribution transformers	No	Yes	Yes
Distribution switchgear	No	Yes	Yes
Other network assets (Load control)	No	No	Yes
Non-network assets (Offices, etc)	Yes	Yes	Yes

The resulting allocators for each group are as follows:

Table 6 Distribution asset utilisation allocators for each consumer group

Distribution assets	Very Large Industrial	C&I	Mass Market
Sub-transmission lines	Dedicated and portion of shared lines (Note 1)	Peak demand in Table 4	Peak demand in Table 4
Sub-transmission cables	Dedicated and portion of shared cables (Note 1)	Peak demand in Table 4	Peak demand in Table 4
Zone substations	Dedicated and portion of shared substations	Peak demand in Table 4	Peak demand in Table 4
HV + LV lines	Nil	HV: Length LV: Nil	HV: Length LV: 100%
HV + LV cables	Nil	HV: Length LV: Nil	HV: Length LV: 100%
Distribution transformers	Nil	HV Length	HV Length
Distribution switchgear	Nil	HV Length	HV Length
Other network assets	Nil	Nil	100%
Non-network assets	Assessment	Assessment	Assessment

Note 1: Details of methodology for allocation of sub-transmission lines and cables to the Very Large Industrial group are as follows:

- Specific sub-transmission lines and cables exclusively supplying Very Large Industrial sites are allocated 100% to the VLI group;
- Sub-transmission lines and cables supplying both Very Large Industrial sites and other consumers are allocated in proportion to the non-coincident peak demands on those assets relating to the VLI sites and the general consumers; and

- Those sub-transmission lines and cables which do not supply VLI consumers are not allocated to the VLI group at all.

The resulting percentages for asset allocations used in Northpower's Cost of Supply Model are:

Table 7 Distribution asset utilisation percentages for each consumer group using FY16 data

Distribution assets	Very Large Industrial	C&I	Mass Market
Sub-transmission lines	15.0%	11.9%	73.1%
Sub-transmission cables	25.0%	11.9%	63.1%
Zone substations	15.0%	11.9%	73.1%
HV + LV lines	0.0%	2.0%	98.0%
HV + LV cables	0.0%	2.0%	98.0%
Distribution transformers	0.0%	2.0%	98.0%
Distribution switchgear	0.0%	2.0%	98.0%
Other network assets	0.0%	0.0%	100.0%
Non-network assets	5.0%	3.0%	92.0%

On the basis of these allocators, the depreciated asset values of each asset category have been allocated to the Consumer Groups:

Table 8 Depreciated distribution asset values allocated to each consumer group for FY18

Distribution assets	Total RAB	Allocation to VLI	Allocation to C&I	Allocation to Mass Market
Sub-transmission lines	$7,778,000	$1,166,700	$926,098	$5,685,202
Sub-transmission cables	$9,894,000	$2,473,500	$1,178,043	$6,242,457
Zone substations	$32,943,000	$4,941,450	$3,922,404	$24,079,146
HV + LV lines	$101,588,000	$0	$2,031,760	$99,556,240
HV + LV cables	$49,367,000	$0	$987,340	$48,379,660
Distribution transformers	$28,685,000	$0	$573,700	$28,111,300
Distribution switchgear	$7,467,000	$0	$149,340	$7,317,660
Other network assets	$5,294,000	$0	$0	$5,294,000
Non-network assets	$10,515,000	$525,750	$315,450	$9,673,800
Totals	**$253,531,000**	**$9,107,400**	**$10,084,136**	**$234,339,464**
		3.6%	4.0%	92.4%

The resulting allocations of asset values are used to allocate Return on Investment (RoI) and depreciation between the three Consumer Groups in Section 9.5 of this document.

9 Allocation of the components of revenue requirements to Consumer Groups

Requirement 2.4.3(1) in the 2012 EDIDD

9.1 Methodology for Very Large Industrial group

Transmission component:

Connection charges are allocated to each VLI site in proportion to the site's contribution to the total peak demand (averaged over the 12 highest GXP peaks in the preceding calendar year) at the relevant grid-connection substation, plus an administration fee.

For example: If the average of the twelve highest GXP demands at a GXP supplying a Very Large Industrial site was 40MW and a Very Large Industrial site's average demand was 10MW at the time of those peaks, and the Connection Charge payable by Northpower to Transpower for that GXP was $10,000 per month, then the Connection Charge for that site would be assessed as 10 ÷ 40 x $10,000 = $2,500 per month + $50 (2%) administration fee.

Prior to 1 April 2013, some grid-connection assets were dedicated to supplying the Very Large Industrial sites and the Connection Charges for those connection assets were allocated entirely to the Very Large Industrial sites. On 1 April 2013, those dedicated assets were included in a transfer of assets from Transpower to Northpower and currently there are no grid-connection assets solely dedicated to the supply of Very Large Industrial sites. Assets at Maungatapere substation dedicated to the supply to Dargaville are excluded from the allocation of Connection Charges for the two Very Large Industrial sites supplied from Maungatapere. On 1 April 2015, a further asset transfer occurred and adjustments were made accordingly.

Transpower's Interconnection charges are allocated to VLI sites on the basis of each VLI site's demands at the times of the highest hundred Upper North Island (UNI) Regional Coincident Peak half-hour Demands (RCPD) in the relevant Capacity Measurement Period (CMP)(which is presently the preceding September - August period) multiplied by the current Interconnection Rate set by Transpower ($123.98 per kW pa from 1 April 2017).

For example: If the average metered half-hour demand for a VLI site at the times of the highest hundred UNI RCPD peaks in the CMP up to August 2016 was 10 MW, then the Interconnection Charges for that site in the year commencing 1 April 2017 would be 10,000 kW x $123.98 per kW pa = $1,239,800 pa = $103,317 per month.

Distribution component:

The distribution component of the pricing for each site is derived as a rate of return on the relevant Northpower assets from the grid-connection substation to the point of connection for the site, plus any on-site assets owned by Northpower. The rate of return includes components for return on assets, depreciation and maintenance. Network assets that are utilised by more than one site are allocated on the basis of the share of the load carried at peak loading (for example: an incoming circuit-breaker with a peak current of 200 amps would be allocated in proportion to an assessment of the share of that 200 amps supplying the end-use site at the peak load).

9.2 Methodology for C&I (Commercial & Industrial) group

Sites with load factors favouring demand-based distribution pricing (subject to a 150 kVA minimum for both the Anytime demand and the Network Peak Period demand) are allocated to this group which has kVA-demand-based distribution prices.

Transmission and distribution costs are both recovered via two demand prices assessed on the basis of actual half-hour demands in specific time-periods from 1 April to 31 March each year. In the 2016/2017 year (FY17), the transmission components will be 36% for the Anytime Demand charge and 50% for the Network Peak Period Demand (44% overall).

The input costs that are common to both the Anytime and the Network Peak Period Demand charges are apportioned between the two, generally (but not exclusively) on a 50/50 basis.

Anytime Demand price:

The chargeable Anytime Maximum Demand (AMD) is the highest half-hour demand at any time each year commencing 1 April. The price provides a contribution to transmission charges, sub-transmission system and the distribution system (11kV lines and distribution transformers).

Most of these sites are supplied directly from distribution transformers, so none of the 400V local distribution costs are allocated to this price category.

Network Peak Period Demand price:

The Network Peak Period Demand price is effectively a "congestion price" assessed at the times when the network is typically at peak load, namely 0700-1000 + 1700-2130 from May to September. These time windows also cover the periods in which the UNI regional peaks have been recorded in recent years.

The price includes a contribution to the interconnection charges, the grid connection, sub-transmission system and the distribution system. It also covers reactive power requirements for power factors of 0.95 or better.

Excess Reactive Power price:

For sites where the power factor falls below 0.95 lagging for the highest half-hourly demand in a month, the excess kVAr is priced at a published rate per excess kVAr.

Customer price:

The monthly customer price covers a portion of Northpower's general administration costs. In cases where Northpower provides half-hour metering, standard metering charges are added.

9.3 Methodology for the Mass-Market group

Daily prices:

Daily prices cover a portion of Northpower's general administration costs. Only one daily price applies per ICP, regardless of the number of variable prices for that ICP.

For ICP's on residential price categories, the daily price for ICP's which are the principal place of residence of a consumer is set in accordance with the Low Fixed Charge Regulations.

Variable prices:

For the Mass-Market group of consumers, the variable prices recover the balance of the costs not recovered by the daily prices, including the return on assets, maintenance costs and operating costs relating to the transmission, sub-transmission, 11kV distribution lines and cables and 400V local distribution. The prices per kWh are intended to reflect the relative costs applicable to the uncontrolled and controlled options available.

Transmission:

Transmission costs are recovered as a portion of the variable prices. Differentials between the transmission components of prices for uncontrolled loads versus prices for controlled loads reflect the differing impacts on the regional peak demands.

9.4 Allocation of Transmission Costs & Revenue to Consumer Groups for FY17/18

9.4.1 Connection Charges

9.4.1.1 Connection Charge costs

Table 9 Connection charges for BRB0331, MPE1101, MTO0331 (and KEN0331 up to 31/03/2015)

Year	Annual Connection Charges
2013/2014 (FY14)	$3,051,705
2014/2015 (FY15)	$3,166,773
2015/2016 (FY16)	$3,482,966 (including $683,348 for Northpower-owned transmission assets)
2016/2017 (FY17)	$3,223,273 (including $690,218 for Northpower-owned transmission assets)
2017/2018 (FY18)	$3,309,304 (including $707,000 for Northpower-owned transmission assets)

Notes:

2013/2014: The Connection Charges that would have been payable for transmission assets acquired from Transpower by Northpower on 1 April 2013 (had the assets not been acquired) are NOT included in these totals – instead an equivalent amount is recovered as part of the distribution prices in section 9.5.

2014/2015: The charges for the 2013 Customer Investment Contract (CIC) are included.

2015/2016 onwards: The transmission assets which transferred from Transpower to Northpower on 1 April 2015 continue to be regarded as transmission assets. For the purposes of the statistical Information Disclosure (in August of each year), charges relevant to acquired transmission assets are treated as transmission costs for up to five years from the acquisition. The Connection Charges that would have been payable for transmission assets acquired from Transpower by Northpower on 1 April 2015 (had the assets not been acquired) are included in the Connection Charges from 2015/2016 onwards in Table 9. The actual charges for the 2013 Customer Investment Contract (CIC) and the charges for the 2015 Customer Investment Contract (CIC) are also included in the Connection Charges for 2015/2016 in Table 9.

From 2016/2017 onwards, only the charges from the 2013 CIC applies.

9.4.1.2 Connection Charge cost allocations

The portion of Connection Charges allocated to the Very Large Industrial group is determined using the methodology described in Section 9.1 of this document. The remainder is allocated between the C&I group and the Mass-market groups in proportion to the peak demands. Refer to Table 4 in section 6 for the

methodology used to determine the peak demands from the C&I and Mass-market groups. Note that the percentages derived from the cost allocations in Table 10 following differ from the percentages derived from the GXP demands in Table 4 because the Connection Charges at BRB are higher per MW than at the other GXP's.

Table 10 Allocation of Connection Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,809,419	54.7%
C&I	Sum of Network Peak Period demands x 60%	$178,586	5.4%
Mass-Market	Residual	$1,321,298	39.9%
Total	**Includes Kensington assets**	**$3,309,303**	**100.0%**

9.4.2 Interconnection Charges

Table 11 Interconnection Charges payable by Northpower from April 2017 (FY18)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, MPE1101, MTO0331	150,687	$123.98	$18,682,174
Generation owners for ACOT	12,361	$123.98	$1,532,517
Total	163,048	$123.98	$20,214,691

ACOT is the "Avoided Cost of Transmission" payments to owners of large embedded generators in accordance with Part 6 of the Electricity Industry Participation Code 2010

Table 12 Allocation of Interconnection Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocator for contribution to RCPD from Table 3 in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $123.98/kW
VLI	Actual demands at times of RCPD	58,874	36%	$7,299,199
C&I	Sum of Network Peak Period demands x 60%	12,106	7%	$1,500,852
Mass-Market	Residual	92,068	56%	$11,414,640
Total		**163,048**	**100%**	**$20,214,691**

9.4.3 Total Transmission Charges

The following tables collate the data relating to Connection Charges and Interconnection Charges.

Table 13 Transmission Charges payable by Northpower from 1 April 2017 (FY18)

Connection Charges	$3,309,303	From Table 9
Interconnection Charges including ACOT	$20,214,691	From Table 11
Total Transmission Charges payable by Northpower	$23,523,994	

Table 14 Allocation of Transmission Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocated Connection Charges (from Table 10)	Allocated Interconnection Charges (from Table 12)	Total
Very Large Industrial	$1,809,419	$7,299,199	$9,108,618
C&I	$178,586	$1,500,852	$1,679,438
Mass-Market	$1,321,298	$11,414,640	$12,735,938
Total	**$3,309,303**	**$20,214,691**	**$23,523,994**

9.4.4 Comparison of cost allocations to budgeted transmission revenue

Table 15 Transmission cost allocations in comparison to expected transmission revenue from 1 April 2017 (FY18)

Consumer Group	Transmission cost allocations from Table 14	Total transmission revenue	Variance from allocations
Very Large Industrial	$9,108,618	$8,936,177	-1.89%
C&I	$1,679,438	$1,804,183	7.43%
Mass-Market	$12,735,938	$13,097,557	2.84%
Total transmission revenue	**$23,523,994**	**$23,837,917**	**1.33%**

The analysis indicates the allocation of transmission charges from 1 April 2015 to each group is efficient. While the variance for the C&I group appears to be significant in terms of percentage for that group, it represents a total of less than $200,000 out of a total of $20m of transmission charges and it being aligned progressively year-on-year.

9.5 Allocation of Distribution Costs & Revenue to Consumer Groups for FY17/18

Northpower has refined its Cost of Supply model (CoS) to allocate the costs applicable to distribution to the three consumer groups.

9.5.1 Allocation of asset-related, system maintenance and business costs

In the CoS model, these costs have been allocated on the following basis:

Table 16 Percentage allocators for distribution costs in FY18

Category	VLI	C&I	MM	Allocator
RoI and depreciation	3.6%	4.0%	92.4%	Asset values from Table 8
System maintenance	3.3%	3.0%	93.7%	Asset values and lengths
Business costs	5.8%	10.0%	84.3%	Nominal

9.5.2 Overall allocation of Distribution Costs to Consumer Groups

Using the allocators in Table 16 above, the Cost of Supply model gave the following:

Table 17 Allocations for distribution costs in FY18

Category	Total to allocate	VLI	C&I	MM	Allocator
Asset-related costs	$25,407,557	$912,696	$1,010,580	$23,484,281	Table 16
System maintenance	$10,593,484	$298,893	$289,047	$10,005,544	Table 16
Business costs	$10,236,868	$591,720	$1,020,548	$8,624,600	Table 16
Totals	**$46,237,908**	**$1,803,309**	**$2,320,174**	**$42,114,425**	
		3.9%	5.0%	91.1%	

9.6 Comparison of Cost Allocations vs Distribution price revenue from each Consumer Group

The final step is to combine the allocations for transmission charges and the distribution costs to derive the total cost allocations for each consumer group in Table 18 following and compare the total allocations to the total revenue for each of the three consumer groups.

Table 18 Total cost allocations versus distribution revenue for each Consumer Group in FY18

Consumer Group	Transmission cost allocations from Table 14	Distribution cost allocations from Table 17	Total cost allocations	Total distribution price revenue	Variance compared allocations
VLI	$9,108,618	$1,803,309	$10,911,927	$10,794,439	-1.1%
C&I	$1,679,438	$2,320,174	$3,999,612	$3,881,657	-2.9%
MM	$12,735,938	$42,114,425	$54,850,363	$55,481,681	1.2%
Total	**$23,523,994**	**$46,237,908**	**$69,761,902**	**$70,157,777**	**0.6%**

The comparisons of budgeted costs against expected revenue per main consumer group in Table 18 indicate that Northpower's distribution price pricing is efficient.

10 Fixed Prices versus Variable Prices

10.1 Fixed prices for Very Large Industrial group

Distribution prices and the pass-through of transmission charges for this group are determined prior to the commencement of each financial year and are effectively 100% fixed for that year. Minor exceptions are the pass-through of Electricity Authority levies (which are set by the Authority on a consumption basis), credits from Loss & Constraints payments and prices for any excessive reactive power requirements which are assessed monthly.

Consumers in this group are generally supplied by dedicated assets or predictable portions of shared assets. As such, it is appropriate to fix the prices for each year.

The distribution portions of the distribution prices are generally determined by contract (either signed or agreed). The pass-through of transmission charges is reassessed each year to fairly reflect the portion of connection charges and the site's contribution to the Regional Coincident Peak Demand (RCPD).

10.2 Fixed prices for C&I group

Distribution prices are effectively 100% fixed for each year on the basis of demand (in kVA). A minor exception is the charge for any excess reactive power requirement is assessed monthly.

The demand charges are reassessed on an annual basis to fairly reflect changes in each site's peak anytime demand and contribution to the winter peak demand.

10.3 Fixed prices for Mass-Market group

Distribution prices are allocated on a two-part basis comprised of a daily fixed price and variable (consumption-related) prices. The mix between fixed and variable prices reflects the Low Fixed Charge Regulations and historical expectations from consumers. Mass-Market consumers have historically had a significant portion of their prices to be based on variable (per kWh) prices, consistent with a "user-pays" approach. In FY18, daily prices are expected to comprise 13% of Northpower's income from line function services for Mass-Market consumers.

Fixed prices for Mass-Market consumers are expressed as "cents per day" or “dollars per day” and cover some of the costs relating to administration, corporate overheads, billing and other non-system overheads. To comply with the Low Fixed Charge Regulations, Northpower’s fixed prices for all residential ICP’s which are the consumer’s principal place of residence is 15 cents/day plus GST plus metering charges.

On 1 April 2015, Northpower introduced a new pricing category for residential premises which do not meet the eligibility criteria in the Low Fixed Charge Regulations of being the principal place of residence for a consumer. This price category has a higher daily price and a lower consumption-based variable price compared to pricing for principal places of residence.

11 Non-Standard Contracts

[Requirements 2.4.1(3) + 2.4.5 (1) + 2.4.5(2) of the 2012 EDIDD]

The 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 5 persons, none of which is a related party to the EDB or to each other. It requires EDB’s to disclose certain details of non-standard contracts, being contracts that do not meet the definition of standard contracts.

11.1 Contracts with the Very Large Industrial sites

As highlighted in Section 1 of this document, nearly all of Northpower’s contracts for the supply of line services are on an interposed basis via retailers. However, Northpower contracts directly with two industrial customers for the line services provided to their very large industrial sites. This is primarily because the values of the Northpower-owned assets dedicated to supply these sites are significant (in the millions of dollars) and robust commercial contracts are prudent to mitigate risk of these assets being stranded.

The sites have dual HV supplies for enhanced security of supply and the cost of this is recovered through the return-on-assets portion of their distribution pricing. In terms of pricing, the general principles are covered by the framework publicly disclosed for the “IND” price category for the Very Large Industrial sites.

The manner in which the pricing was set in these contracts was similar to that used for other sites in the Very Large Industrial group at the time when the contracts were signed but are now locked-in for the duration of the contracts.

11.2 Non-standard arrangement for one site on C&I price category

There is one site on the C&I group for which the Anytime Demand is assessed in a non-standard manner. This site has an atypical load profile which does not fit the normal profile for a C&I consumer so, rather than creating a separate price category for just one site, the Anytime demand is assessed using a modified criterion.

11.3 Target revenue from ICP’s on Non-standard contracts

Total target revenue from ICP’s on Non-standard Contracts for the 2017/2018 year is $7.6m excluding GST.

11.4 Differences in obligations relating to supply interruptions

The two Very Large Industrial sites covered by Non-standard Contracts are continuous-process industries with enhanced requirements for security of supply. The supply to each site is fully duplicated and the relevant costs are recovered through the asset-based distribution pricing.

12 Distributed Generation

[Requirements 2.4.1(3) + 2.4.5 (3) of the 2012 EDIDD]

The EDIDD requires EDB's to disclose their approach to pricing for distributed generation connected to the network. Northpower's approach is as follows:

12.1 Large distributed generation with half-hour metering

For large embedded generators (typically in MW), Northpower adheres to the requirements of Part 6 of the Electricity Industry Participation Code. Specifically, Northpower assesses the generator's average output to the distribution network at the time of the 12 RCPD UNI peak demands in the appropriate Capacity Measurement Period and then credits the generator's owner for this quantity at the prevailing Interconnection price per kW. From 1 April 2017, this will change to averaging across the 100 RCPD UNI demands to reflect the recent operational changes in the TPM.

In December 2016, the Electricity Authority announced that the Distributed Generation Pricing Principles (DGPP) will be amended to remove the requirement on distributors to make ACOT payments to owners of generators. The change will be phased in across New Zealand at various dates, with the Upper North Island changing on 1 April 2019.

12.2 Small distributed generation without half-hour metering

Northpower does not provide credits to owners of very small-scale exported generation because it is impractical to assess whether there are any real reductions of peak load from such generation and, in the case of PV without battery storage, the peak system loads in winter occur after sunset when PV's are not generating.

Northpower will consider introducing a distribution price for exported generation if widespread deployment of PV panels results in additional network investment being required.

13 Price/Quality Trade-off

[Requirement 2.4.1 (4) of the 2012 EDIDD]

Within the Very Large Industrial group, individual contracts specify quality expectations (within the limitations of a shared grid) and set the pricing accordingly. For example, for security of supply reasons, most sites elect to have two incoming feeders, each capable of supplying the load for their entire site, and the asset-based pricing reflects that premium grade of service.

Dedicated on-site distribution transformers for consumers in the C&I group provide a level of immunity from power-quality degradation or interruptions directly attributable to adjacent consumers but they are still vulnerable to network interruptions.

For C&I and Mass-Market, achieving a particular balance between price and quality is generally only practical across the entire network. Consequently, this is a matter that has been included in consumer surveys for several years. Feedback from the surveys and to the shareholder Trust has consistently shown that Mass-Market consumers generally would not be willing to pay higher prices for increased reliability.

14 Pricing Strategy

[Requirement 2.4.4 of the 2012 EDIDD]

14.1 Pricing Strategy – Short Term (including the year commencing 1 April 2017)

The strategy that has been utilised in recent years is as follows:

14.1.1 The existing distribution pricing methodologies currently used within each main consumer group and the relativity between the main consumer groups have not been fundamentally changed because they are considered appropriate to each group.

14.1.2 A general price increase is applied as evenly as practical to the distribution portions of all price categories in the Mass-Market and C&I groups. Previously the percentage was equivalent to a forward estimate in the change in CPI for the year commencing 1 April but from 1 April 2016, this was amended to a minimum increase of 2.5% per annum since the recent low CPI increases were not an accurate reflection of the increases in the costs of operating an electricity network.

For 1 April 2017, the increases will be:

Residential - An average increase of 5% in the variable prices, which is expected to move Northpower's pricing for residential consumers away from the lower end of the range of North Island distributors.

General (non-residential) – Northpower's pricing for general consumers is currently at the midpoint in comparison to other North Island distributors, so the only change proposed is the increase in daily prices as per the following section.

14.1.3 Daily prices for general (non-residential) Mass-Market ICP's are being increased progressively from the original 15 cents per day to 100 cents per day, consistent with Northpower's previously approved strategy to increase the portion of costs recovered through fixed prices.

1 April 2014 = 50 cents per day (Done)
1 April 2015 = 70 cents per day (Done)
1 April 2016 = 85 cents per day (Done)
1 April 2017 = 100 cents per day (Implemented from 1 April 2017)

14.1.4 Daily prices for residential ICP's which are the consumer's principal place of residence remain at 15 cents per day to comply with the Low Fixed Charge Regulations. To maintain overall equivalence between general and residential prices, the variable prices for residential ICP's are now higher than for general ICP's.

14.1.5 A new Price Category for residential ICP's that are not principal places of residence was introduced on 1 April 2015. The price category is compulsory (rather than optional) for ICP's identified by Northpower as non-principal residences.

14.1.6 Distribution portions of the pricing for the Very Large Industrial sites are indexed to the change in PPI for the most recent calendar year, excluding those on non-standard contracts which already have a price adjustment formula.

14.1.7 Transmission costs and ACOT (Avoided Cost of Transmission) are passed-through as transparently as practical.

14.1.8 The ND4 Price Category (Schools Day/Night) was eliminated on 1 April 2015 in recognition of school heating progressively moving from night-storage heating to heat-pumps. The night-rate boosted price was merged with the Controlled 18 hour price.

14.2 Pricing Strategy – longer term – from 1 April 2018

Retailers advised that their major deployments of advanced meters on the Northpower network would be completed by the end of the 2016 calendar year but this is likely to extend to the end of 2017. The data from these meters will be utilised to develop distribution pricing for mass-market consumers that is more service-based.

Changes may include:

- Introduction of peak/off-peak consumption-based components to residential price categories to better reflect the costs of supplying residential properties.
- Development of new price categories (or amendment of existing price categories) to incentivise owners of electric vehicles (EV's) to charge their EV's at off-peak times.

14.3 Changes in Pricing Strategy compared to last year

The long-term strategy will be revised in conjunction with the Future Pricing Strategy being developed by the Electricity Networks Association (ENA) Distribution Pricing Working Group (DPWG).

15 Pricing Rationalisation and Alignment to ENA Guidelines

Rationalisation of Northpower's distribution pricing options resulted in the elimination of three Price categories (ND4, ND11 and ND14) on 1 April 2015, along with the Night-rate boosted price which was merged into the Controlled 18-hour price from 1 April 2015.

The obsolete DM4 all-inclusive price category will be eliminated by 1 April 2018, provided most of the remaining ICP's from the DM4 price category have been moved to other price categories as the current deployments of advanced meters come to an end.

Version 1.1 of the Electricity Networks Association (ENA) Distribution Pricing Guidelines (DPG), published in August 2015, facilitated greater alignment of the structures of price categories and naming conventions. Version 1.1 only covered mass-market pricing. The structure of Northpower's distribution pricing for mass-market consumers already aligned closely to the guidelines but some names needed to be aligned to the guidelines, so, for example, "Residential" replaced "Domestic", and "Uncontrolled" replaced "24 hour" as at 1 April 2016.

Version 2 of the Electricity Networks Association (ENA) Distribution Pricing Guidelines (DPG) has recently been published. Version 2 incorporates the mass-market aspects from version 1.1 and extends to cover larger commercial and industrial consumers. Northpower will, to the extent that is practical, align its pricing and terminology to Version 2 of the DPG from 1 April 2017.

Appendix 1: Glossary

Term	Meaning in the context of this document
AMD	Anytime Maximum Demand. The highest half-hour demand, usually in kVA, during a one year period.
Authority	Electricity Authority (EA)
Avoided Cost of Transmission (ACOT)	A reduction in transmission costs payable to Transpower (usually in the context of embedded generation).
Code	Electricity Industry Participation Code 2010 and subsequent amendments.
Commercial & Industrial consumer (C&I)	Large commercial and industrial consumers supplied by dedicated on-site distribution transformers exceeding 150kVA, excluding the Very Large Industrial sites. Distribution prices for this group are determined by the half-hour kVA demand.
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	An entity other than Transpower which owns an electricity network other than an embedded network. Often denoted as an Electricity Distribution Business (EDB) or an Electricity Lines Business (ELB).
Distributed generation (DG)	An electricity generator connected directly to an electricity distribution network (rather than to the transmission grid). Also called Embedded Generation.
EDIDD 2012	Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission as Decision NZCC 22 dated 1 October 2012 and consolidated in 2015.
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.
kWh	Kilowatt-hour. Rate of energy flow.
Low Fixed Charge Regs	Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004.
Mass-Market consumers	Consumers ranging from households to small businesses.
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 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).
Northpower	Northpower Limited

Term	Meaning in the context of this document
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
Price	A price option. For instance: Uncontrolled or Controlled 18-hour.
Price Category	A subgroup within a Consumer Group.
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 Option for Domestic Consumers) regulations 2004.
RCPD	Regional Coincident Peak Demand.
Residential Consumer	A consumer at a residential ICP which satisfies the definition of "domestic premises" in Section 5 of the Electricity Industry Act 2010.
SOLEC	Separation of Line and Energy Charges – a process undertaken in the 1990's prior to the introduction of competition in the energy sector.
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 5 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.
Trust	Northpower Electric Power Trust (NEPT). The entity which holds all the shares in Northpower on behalf of the consumers.
Upper North Island (UNI)	The area of the North Island north of Huntly.
Very Large Industrial consumers	Large process industries generally operating on a "24/7" basis.

Appendix 2: Cross-References to Requirements in EDIDD 2012

Capitalised terms are defined clause 1.4.3 of the EDIDD 2012

EDIDD clause	EDIDD requirement	Location in the Northpower Pricing Methodology disclosure document
2.4.1 (1)	Describe, as per 2.4.3, the methodology used to calculate prices.	Refer to comments for clause 2.4.3
2.4.1 (2)	Describe any changes in prices and target revenues.	Refer to comments for clause 2.4.3(6)
2.4.1 (3)	Explain, as per 2.4.5, approach to pricing Non-standard Contracts and DG.	Refer to comments for clause 2.4.5
2.4.1 (4)	Interaction with consumers on expectations of price and quality.	Section 13
2.4.2	Changes in methodology to be disclosed 20 working days before prices take effect.	When this document is published on the Northpower website
2.4.3(1)	How prices were set for each Consumer Group, including assumptions and statistics.	Section 9
2.4.3(2)	Extent of consistency and inconsistency to Electricity Authority Pricing Principles.	Appendix 3
2.4.3(3)	Total Target Revenue for disclosure year	Sections 5.1 and 9.6
2.4.3(4)	Numerical values of key components of Target Revenue to cover EDB costs and RoI.	Section 9.5.2
2.4.3(5)(a)	Rationale for Consumer Groups.	Section 6.
2.4.3(5)(b)	Criteria for allocating consumers to Consumer Groups.	Section 7
2.4.3(6)	Reasons for and quantification of changes to previously disclosed prices.	Section 5.2
2.4.3(7)	Method and rationale to allocate Target Revenue to Consumer Groups and numerical values.	Section 9
2.4.3(8)	Proportions of target revenue collected through each price component (individual prices) disclosed under 2.4.18.	Appendix 5
2.4.4(1)	If EDB has a written approved Pricing Strategy, explain next 5 years	Section 14
2.4.4(2)	How and why prices will change for each consumer group.	Sections 5.2 and 14
2.4.4(3)	Explain any changes in Pricing Strategy from preceding year.	Section 14.3
2.4.5(1)(a)	Number of ICP's and target revenue from Non-standard contacts	Section 11
2.4.5(1)(b)	Criteria for use of non-standard contract.	Section 11
2.4.5(1)(c)	Any specific criteria or methodology in Non-Standard Contracts and consistency with the Electricity Authority Pricing Principles.	Section 11 and Appendix 3
2.4.5(2)(a)	Differences in obligations between Standard and Non-standard contracts for supply interruptions.	Section 11
2.4.5(2)(b)	Implications of (a) in prices in Non-standard contracts.	Section 11
2.4.5(3)(a)	Prices for services to DG owners.	Section 12
2.4.5(3)(b)	Value, structure and rationale for any payments to DG owners.	Section 12

Appendix 3: Information for Electricity Authority Pricing Principles Analysis

Requirement 2.4.3(2) of the 2012 EDIDD

The Information Disclosure requirements set by the Commerce Commission require Electricity Lines Businesses to demonstrate how their distribution pricing meets the Pricing Principles adopted by the Electricity Authority. For clarity, the information is presented in tabular format as follows:

Compliance to Final Pricing Principles in Section 3.3 of the "Distribution Pricing Principles and Information Disclosure Guidelines" published by the former Electricity Commission in February 2010

Ref	EA Pricing Principle	Notes on Northpower's compliance at high-level
(a)	Prices are to signal the economic costs of service provision, by:	
(a) (i)	being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulations and/or the Government Policy Statement;	<u>Very Large Industrial group</u> Distribution pricing is asset-based which minimises the risk of creating subsidies. <u>Commercial & Industrial (C&I) group</u> Distribution prices for this group are assessed on the basis of peak demand which ensures the incremental cost of an additional consumer or an increase in demand is recovered. <u>Mass-Market group</u> Generally the incremental cost to connect an additional consumer is very small because LV distribution already exists in most urban areas and HV distribution exists in most rural areas. In cases where the incremental cost to connect is high – specifically when a multi-lot subdivision is reticulated or an additional distribution transformer is required in a rural situation - the cost of connection in excess of a standard amount is recovered as a one-off connection charge to the developer or new consumer, rather than creating a subsidy from all the existing consumers or setting a unique higher distribution Price Category for that area. Northpower identified that subsidies existed for holiday homes for which distribution pricing was previously assessed on the basis of residential prices with low daily prices. Revenue from principal places of residence across the Northpower network averaged around $650 pa, but holiday homes only paid around $300 pa on average due to the lower consumption. While there was some justification for a lower pass-through of transmission prices to holiday homes (due to a lower probability of consumption at holiday homes in Northland at the times of RCPD), the cost of supplying holiday homes from the distribution network is equivalent to the cost of supplying principal places of residence. To address this, Northpower introduced a new Price Category (DM3) from 1 April 2015 for non-principal places of residence with annual consumptions of less than 4000 kWh pa. <u>Subsidies arising from legislation, regulations or Government Policy Statement</u> To the extent that is practical, Northpower seeks to avoid cross-subsidies between the three primary consumer groups (Very Large Industrial, C&I and Mass-Market) by applying the principles outlined in Section 8 of this document.

Ref	EA Pricing Principle	Notes on Northpower's compliance at high-level
		However, there are two significant sources of cross-subsidy within the Mass-Market group, namely: 1. Low-use residential consumers are subsidised by high-use residential consumers due to the requirements of the Low Fixed Charge regulations; and 2. Rural consumers are, to some extent, subsidised by urban consumers due to the higher costs to supply rural areas not being reflected in any rural/urban differential in distribution prices. The owners' view is that electricity has been provided for the common good of the community, so some level of cross-subsidy is acceptable. In practice, the level of price subsidisation is offset by higher volumes in the rural area (for example, a dairy farm uses significantly more electricity than an urban household). Previous research on the prospect of charging higher prices to consumers who can be classified as "remote rural" indicated that the impact on remaining consumers would be insignificant.
(a) (ii)	having regard, to the extent practicable, to the level of available service capacity; and	**Very Large Industrial group** Service capacities are in the range from around 5 MVA to 50 MVA which are generally determined by the rating of the dedicated assets supplying the sites. As the distribution pricing for these sites has been set on the basis of asset utilisation, there is a direct correlation between the value of the assets which determine the available capacity provided to the site and the prices. **Commercial & Industrial (C&I) group** Service capacities for sites in the C&I group are generally determined by the rating of the dedicated distribution transformers supplying the sites which range from 150kVA to 2MVA. These sites are assessed on the basis of peak half-hour demand as a proxy for capacity which, in Northpower's opinion, is more reflective of network capacity utilisation than, for example, charging on the basis of transformer capacity. **Mass-Market group** For the Mass-Market group, Northpower groups the connections into two main groups on the basis of capacity: • All connections of 100A or less; • Connections in the range 120A to 500A with CT metering. The daily prices for connections with service capacities in the range 120A to 500A are significantly higher than for those up to 100A to reflect the higher service capacity. Apart from the Price Category for connections with CT metering, Northpower does not distinguish between service capacities within the Mass-Market group - the rationale for this includes a lack of reliable records for the service fuse ratings and the need for Northpower to have flexibility to optimise the configuration of 400V connections. In the future, advanced metering will provide quantitative data for each consumer's utilisation of network capacity and this will facilitate smarter capacity-based pricing, subject to legislative barriers (including the Low Fixed Charge regulations) being revisited.
(a) (iii)	signalling, to the extent practicable, the impact of additional	**Very Large Industrial group** For the Very Large Industrial group, additional consumption does not generally necessitate additional investment until such time as the assets need augmentation for capacity or security of supply reasons.

Ref	EA Pricing Principle	Notes on Northpower's compliance at high-level
	usage on future investment costs.	The asset-based pricing regime for this group contains direct linkages to future investment costs in terms of signalling the point at which additional investment will be required. **Commercial & Industrial (C&I) group** For sites in the C&I group, additional usage leading to higher peaks results in higher distribution prices, whereas additional consumption due to improved load factors does not incur higher distribution prices. This reflects the impact on future investment in the network which is generally linked to peak loading rather than throughput (consumption). **Mass-Market group** For the Mass-Market group, Northpower's distribution pricing structure does not signal the economic costs of providing incremental network capacity. Due to the expectations on line companies to variablise a substantial portion of distribution pricing for Mass-Market consumers, it is not currently practical to signal the future investment costs to the Mass-Market group. High consumption-based prices discourage all additional consumption, not just that which triggers future investment. This has a common-good aspect where consumers are encouraged to take economic and sustaining actions such as installing better house insulation, more efficient appliances and lighting, and adopting energy-saving behaviours. However, the distortion of overstated consumption-based costs increasingly risks perverse outcomes; of particular concern is residential investment in PV's without adequate storage where the consumer saves on the consumption-based price for the electricity provided by the solar power but the consumer still relies on the electricity network at peak times, meaning that their investment in PV is indirectly subsidised by other consumers. Another long-standing exception is the use of low-priced resistance heaters. In the future, the introduction of advanced metering will facilitate peak-demand pricing for individual ICP's to provide a signal of the cost of adding additional load which will be essential to fairly reflect the effects of new technologies including distributed generation and electric vehicles. Forecasts of growth and investment are detailed in Northpower Asset Management Plan (AMP) which is also publicly disclosed at http://northpower.com/about/disclosures/asset-management-plan
(b)	Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness to the extent practicable.	**Very Large Industrial group** These consumers must manage their load within the constraints of the dedicated assets supplying their sites. If they intend increasing their demand in excess of the current capacity, then they must enter into negotiations for additional capacity resulting in increased costs. **C&I group** Capacity is limited by the dedicated on-site distribution transformers and is subject to a minimum of 150 kVA for the Anytime Demand price and the Network Peak Period Demand price. **Mass-Market group**

Ref	EA Pricing Principle	Notes on Northpower's compliance at high-level
		Northpower, like most other distributors, is expected (and, for residential consumers, is compelled by the Low Fixed Charge regulations) to set distribution pricing structures for Mass-Market consumers that are mostly consumption-based. As such it is not currently practical to set prices that are responsive to demand but that may change in 2017. By substantially discounting prices for separately-metered controlled load, Northpower encourages consumers to make load available for control at peak periods. This is utilised by Northpower to reduce network load during peak-demand times. However, consumers delegate the demand responsiveness to Northpower for the general control of the electricity system demand, rather than being responsive individually to pricing signals.
(c)	Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to: (i) discourage uneconomic bypass; (ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and (iii) where network economics warrant, and to the extent practical encourage investment in transmission distribution alternatives (e.g. distributed generation or demand response) and technology innovation.	**(i) Uneconomic bypass** Very Large Industrial group: Northpower's transparent pass-through of transmission pricing discourages uneconomic bypass of the network. Some Very Large Industrial consumers could connect directly to the grid but the transparent pass-through of transmission pricing ensures that it is consistently more economic for them to connect via the distribution network. C&I group: For consumers on this group with more than one ICP on a single site, Northpower assesses the chargeable demands across the combined load to give the consumer the benefit of load diversity and therefore discourages bypass. Mass-Market group: The low daily price actually encourages uneconomic bypass. Installation of distributed generation such as solar panels on houses reduces consumption but does not reduce the peak demand on the network. By rewarding reduction in consumption through consumption-based pricing, the bypass is encouraged in spite of not reducing network costs. **(ii) Price/quality trade-offs** *(As per Section 13 of the main part of this disclosure)* Very Large Industrial group: Within the Very Large Industrial group, individual contracts specify quality expectations (within the limitations of a shared grid) and set the pricing accordingly. For security of supply reasons, most sites elect to have two incoming feeders, each capable of supplying the load for their entire site, and the asset-based prices reflect that premium grade of service. C&I group: Dedicated on-site distribution transformers for consumers in the C&I group provide a level of immunity from power-quality degradation or interruptions directly attributable to adjacent consumers but they are still vulnerable to network interruptions. Mass-Market group: For the Mass-Market group, achieving a particular balance between price and quality is generally only practical across the entire network. Consequently, this is a matter that has been included in consumer surveys for several years. Feedback from the surveys and to the shareholder Trust has consistently shown that Mass-Market consumers generally would not be willing to pay higher prices for increased reliability. **(iii) Distributed generation:** *(Also relevant to requirement 2.4.5(3) of the EDIDD 2012)* For large-scale distributed generation with half-hour metering, Northpower adheres to the requirements of the Code and pays the

Ref	EA Pricing Principle	Notes on Northpower's compliance at high-level
		generators for actual reductions in transmission costs from Transpower (ACOT). Northpower's variable price for small-scale local distributed generation connected to the Northpower network has been set to zero because there is generally no reduction in transmission costs attributable to these installations. Similarly, at present, there are no locations on the Northpower network where small-scale local distributed generation would potentially defer capital investment in distribution. On the contrary, widespread deployment of PV panels is likely to require additional investment by Northpower to provide capacity and voltage regulation for large quantities of exported generation at times of low load on sunny days. **Demand response:** Northpower's distribution pricing for controlled load is substantially discounted relative to uncontrolled load. For example, in the DM1 Price Category for residential connections, the price for separately-metered 18-hour controlled load is 4.15 cents/kWh compared to 12.70 cents/kWh for uncontrolled load. While that differential in prices might appear to be excessive, it is diluted at the retail level seen by the consumers; for instance, adding an energy price of 12 cents/kWh gives 16.15 cents/kWh for controlled load and 24.70 cents/kWh for uncontrolled load which is a discount of around 35%. A discount of 33% to 50% is quoted by some ELB's as the threshold for consumers to be willing to make controlled load available.
(d)	Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.	**Very Large Industrial group** Considerable volatility and uncertainty results for the application of the Transmission Pricing Methodology (TPM) in relation to the pass-through of the relevant transmission charges for each large site. A recent revision of the TPM created a massive price shock at one GXP with no provision for spreading the impact over a number of years. Therefore, for this group, the current revisiting of the TPM creates the greatest uncertainty in respect to price stability but this is entirely beyond the control of Northpower. **Mass-Market and C&I consumer groups** Northpower spreads any required changes over a number of years. For example, the overall cost (daily price + variable prices) for residential and small general consumers were equalised progressively over a period of about 5 years.
(e)	Development of prices should have regard to the impact of transaction costs on retailers and should be economically equivalent across retailers.	Northpower responded to requests from retailers to reduce the number of Distribution Price Categories because retailers considered any complexity increased their costs to serve. Northpower publishes a single set of Distribution Price Categories, and prices for all retailers supplying consumers on the Northpower network.

Appendix 4: Allocators for Transmission from Previous Years

For reference purposes, the allocators used in Sections 6 and 9 in previous years are:

Contributions to peak regional demand

Table 3A Contributions to peak regional demand August 2012 (for FY14 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at RCPD times	46,805	30%
C&I	60% x sum of Network Peak Period demands	11,475	7%
Mass-Market	Residual	95,686	62%
RCPD + generation		**153,966**	**100%**

The average of the twelve highest regional peaks from the Capacity Measurement Period (CMP) from September 2011 to August 2012 was used by Transpower to set the Interconnection Charges for the year commencing 1 April 2013.

Table 3B Contributions to peak regional demand to August 2013 (for FY15 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at RCPD times	49,153	32%
C&I	60% x sum of Network Peak Period demands	11,695	8%
Mass-Market	Residual	92,716	60%
RCPD + generation		**153,564**	**100%**

The average of the twelve highest regional peaks from the Capacity Measurement Period (CMP) from September 2012 to August 2013 was used by Transpower to set the Interconnection Charges for the year commencing 1 April 2014.

Table 3C Contribution to peal regional demand to August 2014 (for FY16 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at RCPD times	45,502	29%
C&I	60% x sum of Network Peak Period demands	11,960	8%
Mass-Market	Residual	97,046	63%
RCPD + generation		**154,508**	**100%**

The average of the twelve highest regional peaks from the Capacity Measurement Period (CMP) from September 2013 to August 2014 was used by Transpower to set the Interconnection Charges for the year commencing 1 April 2015.

Table 3D Contributions to peak regional demand to August 2015 (for FY17 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at RCPD times	49,190	31%
C&I	60% x sum of Network Peak Period demands	12,397	8%
Mass-Market	Residual	94,639	61%
RCPD + generation		**156,226**	**100%**

The average of the twelve highest regional peaks from the Capacity Measurement Period (CMP) from September 2014 to August 2015 were used by Transpower to set the Interconnection Charges for the year commencing 1 April 2016.

Table 3E Contributions to peak regional demands to August 2016 (for FY18 pricing)

Group	Allocator	Contribution to regional peaks in kW	Percent
Very Large Industrial	Actual demands at times of RCPD	58,874	36%
C&I	Sum of Network Peak Period demands x 60%	12,106	7%
Mass-Market	Residual	92,068	56%
RCPD + generation		**163,048**	**100%**

The average of the highest hundred regional highest demands from the Capacity Measurement Period (CMP) from September 2015 to August 2016 was used by Transpower to set the Interconnection Charges for the year commencing 1 April 2017.

Contributions to peak GXP demand

Table 4A Contribution to GXP peak demands in 2012 (for FY14 pricing)

Group	Allocator	Contribution to GXP demands	Percent
Very Large Industrial	Actual demands at GXP peaks	49,640	29%
C&I	60% x sum of Network Peak Period demands	11,475	7%
Mass-Market	Residual	112,435	65%
	Sum of averages of 12 highest GXP demands	**173,550**	**100%**

Table 4B Contribution to GXP peak demands in 2013 (for FY15 pricing)

Group	Allocator	Contribution to GXP demands	Percent
Very Large Industrial	Actual demands at GXP peaks	60,431	35%
C&I	60% x sum of Network Peak Period demands	11,695	7%
Mass-Market	Residual	101,309	58%
	Sum of averages of 12 highest GXP demands	**173,435**	**100%**

Table 4C Contribution for GXP peak demands in 2014 (for FY16 pricing)

Group	Allocator	Contribution to GXP demands	Percent
Very Large Industrial	Actual demands at GXP peaks	56,257	33%
C&I	60% x sum of Network Peak Period demands	11,960	7%
Mass-Market	Residual	101,609	60%
	Sum of averages of 12 highest GXP demands	**169,826**	**100%**

Table 4D Contributions to GXP peal demands in 2015 (for FY17 pricing)

Group	Allocator	Contribution to GXP demands	Percent
Very Large Industrial	Actual demands at GXP peaks	57,968	36%
C&I	60% x sum of Network Peak Period demands	12,397	8%
Mass-Market	Residual	90,283	56%
	Sum of averages of 12 highest GXP demands	**160,648**	**100%**

The sum of the averages of the 12 highest GXP peaks was lower in 2015 than in 2014 as a consequence of the amalgamation of two GXP's reducing the diversity factor.

There was a significant step increase at one VLI site in November 2015, so Table 4D was derived from data for January to October 2015.

Table 4E Contributions to GXP peak demand in 2016 (for FY18 pricing)

Group	Allocator	Contribution to GXP demands	Perc
Very Large Industrial	Actual demands at GXP peaks	67,663	40%
C&I	Sum of Network Peak Period Demands x 60%	12,106	7%
Mass-Market	Residual	89,565	53%
	Sum of averages of 12 highest GXP demands	**169,334**	**100%**

Allocations of Connection Charges to Consumer Groups

Table 10A Allocation of Connection Charges to Consumer Groups from 1 April 2013 (FY14)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,492,075	48.9%
C&I	Sum of Network Peak Period Demands x 60%	$144,433	4.7%
Mass-Market	Residual	$1,415,197	46.4%
Total		**$3,051,705**	100.0%

Table 10B Allocation of Connection Chargers to Consumer Groups from 1 April 2014 (FY15)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,571,552	49.6%
C&I	Sum of Network Peak Period Demands x 60%	$165,095	5.2%
Mass-Market	Residual	$1,430,126	45.2%
Total		**$3,166,773**	100.0%

Table 10C Allocation of Connection Charges to Consumer groups from 1 April 2015 (FY16)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,606,401	46.1%
C&I	Sum of Network Peak Period demands x 60%	$197,618	5.7%
Mass-Market	Residual	$1,678,946	48.2%
Total	Includes Kensington assets	**$3,482,965**	100.0%

Table 10D Allocation of Connection Charges to Consumer Groups from 1 April 2016 (FY17)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,691,929	52.5%
C&I	Sum of Network Peak Period demands x 60%	$184,880	5.7%
Mass-Market	Residual	$1,346,464	41.8%

Total	Includes Kensington assets	**$3,223,273**	100.0%

Table 10E Allocation of Connection Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocator for contribution to GXP peak demands	Allocated cost	Percent
Very Large Industrial	Methodology described in Section 9.1	$1,809,419	54.7%
C&I	Sum of Network Peak Period demands x 60%	$178,586	5.4%
Mass-Market	Residual	$1,321,298	39.9%
Total	Includes Kensington assets	**$3,309,303**	100.0%

Interconnection Charges

Table 11A Interconnection Charges payable by Northpower from 1 April 2013 (FY14)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, KEN0331, MPE1101, MTO0331	143,667	$99.44	$14,286,246
Generation owners for ACOT	10,299	$99.44	$ 1,024,133
Total	**153,966**	**$99.44**	**$15,310,379**

Table 11B Interconnection Charges payable by Northpower from 1 April 2014 (FY15)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, KEN0331, MPE1101, MTO0331	142,644	$114.47	$16,328,459
Generation owners for ACOT	10,920	$114.47	$ 1,250,012
Total	**153,564**	**$114.47**	**$17,578,471**

Table 11C Interconnection Charges payable by Northpower from 1 April 2015 (FY16)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, MPE1101, MTO0331	142,431	$110.35	$15,717,261
Generation owners for ACOT	12,077	$110.35	$ 1,332,697
Total	**154,508**	**$110.35**	**$17,049,958**

Table 11D Interconnection Charges payable by Northpower from 1 April 2016 (FY17)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, MPE1101, MTO0331	144,899	$114.64	$16,611,221
Generation owners for ACOT	11,327	$114.64	$1,298,527
Total	**156,226**	**$114.64**	**$17,909,749**

Table 11E Interconnection Charges payable by Northpower from 1 April 2017 (FY18)

Payable to	Average kW at RCPD	Interconnection rate	Interconnection charges pa
Transpower for BRB0331, MPE1101, MTO0331	150,687	$123.98	$18,682,174
Generation owners for ACOT	12,361	$123.98	$1,532,517
Total	**163,048**	**$123.98**	**$20,214,691**

Allocations of Interconnection Charges to Consumer Groups

Table 12A Allocation of Interconnection Charges to Consumer Groups from 1 April 2013 (FY14)

Consumer Group	Allocator for contribution to RCPD from Table 3A in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $99.44/kW
VLI	Actual demands at times of RCPD	46,805	30%	$4,654,289
C&I	Sum of Network Peak Period demands x 60%	11,475	7%	$1,141,074
Mass-Market	Residual	95,686	62%	$9,515,016
Total		**153,966**	**100%**	**$15,310,379**

Table 12B Allocation of Interconnection Charges to Consumer Groups from 1 April 2014 (FY15)

Consumer Group	Allocator for contribution to RCPD from Table 3B in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $114.47/kW
VLI	Actual demands at times of RCPD	49,153	32%	$5,626,544
C&I	Sum of Network Peak Period demands x 60%	11,695	8%	$1,338,750
Mass-Market	Residual	92,716	60%	$10,613,178
Total		**153,564**	**100%**	**$17,578,471**

Table 12C Allocation of Interconnection Charges to Consumer Groups from 1 April 2015 (FY16)

Consumer Group	Allocator for contribution to RCPD from Table 3C in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $110.35/kW
VLI	Actual demands at times of RCPD	45,502	29%	$5,021,146
C&I	Sum of Network Peak Period demands x 60%	11,960	8%	$1,319,764
Mass-Market	Residual	97,046	63%	$10,709,048
Total		**154,508**	**100%**	**$17,049,958**

Table 12D Allocation of Interconnection Charges to Consumer Groups from 1 April 2016 (FY17)

Consumer Group	Allocator for contribution to RCPD from Table 3D in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $114.64/kW
VLI	Actual demands at times of RCPD	49,190	31%	$5,639,142
C&I	Sum of Network Peak Period demands x 60%	12,397	8%	$1,421,146
Mass-Market	Residual	94,639	61%	$10,849,461
Total		**156,226**	**100%**	**$17,909,749**

Table 12E Allocation of Interconnection Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocator for contribution to RCPD from Table 3E in section 6	Contribution to RCPD in kW	Percent	Allocated cost at $123.98/kW
VLI	Actual demands at times of RCPD	58,874	36%	$7,299,199
C&I	Sum of Network Peak Period demands x 60%	12,106	7%	$1,500,852
Mass-Market	Residual	92,068	56%	$11,414,640

Total		**163,048**	**100%**	**$20,214,691**

Total transmission charges payable

The following tables collate the data relating to Connection Charges from Table 10A to 10E and Interconnection Charges from Tables 12A to 12E.

Table 13A Transmission Charges payable by Northpower from 1 April 2013 (FY14)

Connection Charges	$ 3,051,705	From Table 9
Interconnection Charges including ACOT	$15,310,379	From Table 11A
Total Transmission Charges payable by Northpower	**$18,362,084**	

Table 13B Transmission Charges payable by Northpower from 1 April 2014 (FY15)

Connection Charges	$ 3,166,773	From Table 9
Interconnection Charges including ACOT	$17,578,471	From Table 11B
Total Transmission Charges payable by Northpower	**$20,745,244**	

Table 13C Transmission Charges payable by Northpower from 1 April 2015 (FY16)

Connection Charges	$ 3,482,966	From Table 9
Interconnection Charges including ACOT	$17,049,958	From Table 11C
Total Transmission Charges payable by Northpower	**$20,532,924**	

Table 13D Transmission Charges payable by Northpower from 1 April 2016 (FY17)

Connection Charges	$3,223,273	From Table 9
Interconnection Charges including ACOT	$17,909,749	From Table 11D
Total Transmission Charges payable by Northpower	**$21,133,022**	

Table 13 Transmission Charges payable by Northpower from 1 April 2017 (FY18)

Connection Charges	$3,309,303	From Table 9
Interconnection Charges including ACOT	$20,214,691	From Table 11
Total Transmission Charges payable by Northpower	**$23,523,994**	

Total Transmission Charge cost allocations

Table 14A Allocation of Transmission Charges to Consumer Groups from 1 April 2013 (FY14)

Consumer Group	**Allocated Connection Charges (from Table 10A)**	**Allocated Interconnection Charges (from Table 12A)**	**Voltage support charges**	**Total**
Very Large Industrial	$1,492,075	$4,654,289	$181,300	$6,327,664
C&I	$144,433	$1,141,074	$25,900	$1,311,407
Mass-Market	$1,415,197	$9,515,016	$162,800	$11,093,012
Total	$3,051,705	**$15,310,379**	**$370,000**	**$18,732,084**

Table 14 B Allocation of Transmission Charges to Consumer Groups from 1 April 2014 (FY15)

Consumer Group	Allocated Connection Charges (from Table 10B)	Allocated Interconnection Charges (from Table 12B)	Total
Very Large Industrial	$1,571,552	$5,626,544	$7,198,096
C&I	$165,095	$1,338,750	$1,503,845
Mass-Market	$1,430,126	$10,613,178	$12,043,303
Total	**$3,166,773**	**$17,578,471**	**$20,745,244**

Table 14C Allocation of Transmission Charges to Consumer Groups from 1 April 2015 (FY16)

Consumer Group	Allocated Connection Charges (from Table 10C)	Allocated Interconnection Charges (from Table 12C)	Total
Very Large Industrial	$1,606,401	$5,021,146	$6,627,547
C&I	$197,618	$1,319,764	$1,517,382
Mass-Market	$1,678,946	$10,709,048	$12,387,994
Total	**$3,482,965**	**$17,049,958**	**$20,532,923**

Table 14D Allocation of Transmission Charges to Consumer Groups from 1 April 2016 (FY17)

Consumer Group	Allocated Connection Charges (from Table 10D)	Allocated Interconnection Charges (from Table 12D)	Total
Very Large Industrial	$1,691,929	$5,639,142	$7,331,071
C&I	$184,880	$1,421,146	$1,606,026
Mass-Market	$1,346,464	$10,849,461	$12,195,925
Total	**$3,223,273**	**$17,909,749**	**$21,133,022**

Table 14E Allocation of Transmission Charges to Consumer Groups from 1 April 2017 (FY18)

Consumer Group	Allocated Connection Charges (from Table 10E)	Allocated Interconnection Charges (from Table 12E)	Total
Very Large Industrial	$1,809,419	$7,299,199	$9,108,618
C&I	$178,586	$1,500,852	$1,679,438
Mass-Market	$1,321,298	$11,414,640	$12,735,938
Total	**$3,309,303**	**$20,214,691**	**$23,523,994**

Comparison of cost allocations to budgeted transmission revenue from each Consumer Group

Table 15A Transmission cost allocations in comparison to transmission revenue from 1 April 2013 (FY14)

Consumer Group	Transmission cost allocations from Table 14A	Total transmission revenue	Variance from allocations
Very Large Industrial	$6,327,664	$6,812,410	7.66%
C&I	$1,311,407	$1,699,671	29.61%
Mass-Market	$11,093,012	$10,907,277	-1.67%
Total transmission revenue	**$18,732,084**	**$19,419,358**	3.67%

Table 2 Transmission cost allocations in comparison to expected transmission revenue from 1 April 2014 (FY15)

Consumer Group	Transmission cost allocations from Table 14B	Total transmission revenue	Variance from allocations
Very Large Industrial	$7,198,096	$7,257,707	0.83%
C&I	$1,503,845	$1,929,982	28.34%
Mass-Market	$12,043,303	$11,722,068	-2.67%
Total transmission revenue	**$20,745,244**	**$20,909,757**	0.79%

Table 15C Transmission cost allocations in comparison to expected transmission revenue from 1 April 2015 (FY16)

Consumer Group	Transmission cost allocations from Table 14C	Total expected transmission revenue	Variance from allocations
Very Large Industrial	$6,627,547	$6,768,952	2.13%
C&I	$1,517,382	$1,905,718	25.59%
Mass-Market	$12,387,994	$12,412,235	0.20%
Total transmission revenue	**$20,532,923**	**$21,086,905**	2.70%

Table 15D Transmission cost allocations in comparison to expected transmission revenue from 1 April 2016 (FY17)

Consumer Group	Transmission cost allocations from Table 14D	Total transmission revenue	Variance from allocations
Very Large Industrial	$7,331,071	$7,163,835	-2.28%
C&I	$1,606,026	$1,804,183	12.34%
Mass-Market	$12,195,925	$12,659,317	3.80%
Total transmission revenue	**$21,133,022**	**$21,627,335**	2.34%

Table 15E Transmission cost allocations in comparison to expected transmission revenue from 1 April 2017 (FY18)

Consumer Group	Transmission cost allocations from Table 14E	Total transmission revenue	Variance from allocations
Very Large Industrial	$9,108,618	$8,936,177	-1.89%
C&I	$1,679,438	$1,804,183	7.43%
Mass-Market	$12,735,938	$13,097,557	2.84%
Total transmission revenue	**$23,523,994**	**$23,837,917**	1.33%

Appendix 5: Proportions of Target Revenue from each Price Component

Requirement 2.4.3(8) of the 2012 EDIDD

There is a requirement to disclose the proportion of total revenue to be collected through each Price Component of the Distribution Pricing disclosure. Some price components have two or more Price Component Codes for compatibility with the billing software so, for clarity, they have been grouped together in the following analysis.

Distribution Price Component	Price Component Code	Percentage of total FY18 budgeted distribution revenue
Mass-Market group		
General daily price	A, P	4.8%
Large Commercial daily price	B	0.3%
Principal place of residence daily price	C, X	3.3%
Non-principal residence daily price	W	1.5%
Builders Temporary Supply daily price	T	0.2%
Residential Uncontrolled	02	36.5%
All-inclusive (Obsolete)	71	0.6%
Non-principal Residence Uncontrolled	03	0.6%
General Uncontrolled	33, 43	14.2%
Large Commercial Uncontrolled	32	4.9%
Metered lighting	19	0.03%
Builders Temporary Supply Uncontrolled	53	0.05%
Controlled 18 hour	06, 46	4.7%
Controlled 22 hour	05, 55	2.8%
Night only	07, 47	0.04%
Controlled day	11	0.2%
Controlled night	12	0.1%
Daily price per unmetered installation	G	0.1%
Unmetered Uncontrolled	25	0.03%
Daily price per unmetered light fitting	H	1.1%
Half-hour metered volume-based daily price	J	0.1%
Half-hour metered volume-based	31	2.8%
Total for Mass-Market group		**79%**
C&I group		
Code 9 - Demand-based prices	9	5.9%
Distribution Price Component	**Price Component Code**	**Percentage of total FY18 budgeted distribution revenue**
Very Large Industrial group		
Very Large Industrial sites	IND	15.3%
Total		**100%**

Appendix 6: Detailed Prices from 1 April 2017 – included for reference only

Table 1 Residential Connections

Price Category Code	Price Component Code	Description	Register Content Code + Available Hours	Availability per day	Delivery price from 1 April 2017	Units
DM1		PRINCIPAL PLACE OF RESIDENCE				
43,921 ICP's	C	Daily price			$0.15	$/day/ICP
	02	Uncontrolled	UN24	24 hours	$0.1340	$/kWh
	06	Controlled 18 hour	CN18	18 hours	$0.0440	$/kWh
	07	Night only	NC8	2300-0700	$0.0160	$/kWh
	24	Unmetered lighting	CN12	Dusk to dawn	$0.0975	$/kWh
	92	Exported generation	EG24	24 hours	$0.0000	$/kWh
DM3		NON-PRINCIPAL RESIDENCE				
3,009 ICP's	W	Daily price			$1.00	$/day/ICP
	03	Uncontrolled	UN24	24 hours	$0.0970	$/kWh
	06	Controlled 18 hour	CN18	18 hours	$0.0440	$/kWh
	07	Night only	NC8	2300-0700	$0.0160	$/kWh
	92	Exported generation	EG24	24 hours	$0.0000	$/kWh
DM4		INCLUSIVE (Obsolete)				
214 ICP's	X	Daily price			$0.15	$/day/ICP
(Closed)	71	All Inclusive	IN18	24hr+18hr	$0.1000	$/kWh
	24	Unmetered lighting	CN12	Dusk to dawn	**$0.0975**	$/kWh
NEWICP	N	**NEWLY CREATED ICP**			**$0.00**	$/day/ICP

Table 2 General Connections

Price Category Code	Price Component Code	Description	Register Content Code + Available Hours	Availability per day	**Delivery price from 1 April 2017**	Units
ND1		Up to 70kVA (100A or less)				
9,513 ICP's	A	Daily price			**$1.00**	$/day/ICP
	33	Uncontrolled	UN24	24 hours	**$0.1130**	$/kWh
	05	Controlled 22 hour	CN22	22 hours	**$0.0740**	$/kWh
	46	Controlled 18 hour	CN18	18 hours	**$0.0440**	$/kWh
	47	Night only	NC8	2300-0700	**$0.0160**	$/kWh
	19	Metered lighting	CN12	Dusk to dawn	**$0.0975**	$/kWh
	24	Unmetered lighting	CN12	Dusk to dawn	**$0.0975**	$/kWh
	93	Exported generation	EG24	24 hours	**$0.0000**	$/kWh
ND2		Greater than 70kVA (CT metering)				
354 ICP's	B	Daily price			**$1.90**	$/day/ICP
	32	Uncontrolled	UN24	24 hours	**$0.1100**	$/kWh
	55	Controlled 22 hour	CN22	22 hours	**$0.0740**	$/kWh
	46	Controlled 18 hour	CN18	18 hours	**$0.0440**	$/kWh
	47	Night only	NC8	2300-0700	**$0.0160**	$/kWh
	93	Exported generation	EG24	24 hours	**$0.0000**	$/kWh
ND5		IRRIGATION and PUMPS		CONTROLLED DAY/NIGHT		
88 ICP's	P	Daily price			**$1.00**	$/day/ICP
	11	Controlled day	DC16	0700-2300*	**$0.0780**	$/kWh
	12	Controlled night	NC8	2300-0700*	**$0.0360**	$/kWh
	33	Uncontrolled	UN24	24 hours	**$0.1130**	$/kWh
	05	Controlled 22 hour	CN22	22 hours	**$0.0740**	$/kWh
ND6		UNMETERED 24 HOUR				
209 ICP's	G	Daily price			**$1.00**	$/day/ICP
	25	Unmetered	CN12	24 hours	**$0.1130**	$/kWh
ND7		UNMETERED PUBLIC LIGHTING				
13 ICP's	H	Daily price			**$0.28**	$/day/fixture
	26	Unmetered lighting	CN12	Dusk to dawn	**$0.0000**	$/kWh

Price Category Code	Price Component Code	Description	Register Content Code + Available Hours	Availability per day	**Delivery price from 1 April 2017**	Units
ND12		BUILDERS TEMPORARY SUPPLY				
444 ICP's	T	Daily price			**$1.40**	$/day/ICP
	53	Uncontrolled	UN24	24 hours	**$0.1130**	$/kWh
ND13 292 ICP's	L	LONG TERM DISCONNECTED			**$0.00**	$/day/ICP
NEWICP		NEWLY CREATED ICP			**$0.00**	$/day/ICP

* Price Code 11/12 is subject to control as per Price Code 05

Table 3 Large Commercial & Industrial sites with half-hour metering

Price Category Code	Price Component Code	Description	Availability per day	**Delivery price from 1 April 2017**	Units
ND9		DEMAND-BASED PRICING			
77 ICP's	D	Monthly price		**$120.00**	$/month
	09AD	Anytime Maximum Demand	24 hours	**$6.70**	$/kVA/month
	09SD	Network Peak Period Demand		**$9.00**	$/kVA/month
	09RP	Excess Reactive power		**$1.62**	$/excess kVAr/month
ND10		VOLUME-BASED PRICING			
86 ICP's	J	Daily price		**$2.60**	$/day/ICP
	31	Uncontrolled	24 hours	**$0.1130**	$/kWh
	31RP	Excess Reactive energy		**$0.0300**	$/excess kVArh
	103	Exported generation	24 hours	**$0.0000**	$/kWh

Table 4 Very Large Industrial sites with individual pricing

Price Category Code	Description	Price from 1 April 2017	Units
IND	**INDIVIDUAL PRICING**		
6 ICP's	**Transmission**		
22	Connection	Assessed per site	$/month/site
23	Interconnection	$123.98	$/kW per annum
24	Excess Reactive power	$1.62	$/excess kVAr per month
25	Electricity Authority levies	Price varies monthly	$/kWh
26	**Distribution**		
27	Distribution	Assessed per site	$/month/site
28	Transmission administration	2% unless agreed otherwise.	$/month
29	**Loss & Constraint**	Rate varies monthly	$/kWh

Appendix 7: Description of Price Categories

Cat	Name	Description
DM1	PRINCIPAL PLACE OF RESIDENCE	This price category is for all ICP's that meet the definition of "domestic" in the Electricity Industry Act 2010 and which are the principal place of residence for the consumer in accordance with clause 3 of the Electricity (Low Fixed charge for domestic consumers) regulations, apart from those in DM4. DM1 has separate prices for the daily price, uncontrolled load and controlled load. The daily price in DM1 meets the requirements of the Electricity (Low Fixed charge for domestic consumers) regulations.
DM2	Reserved	Reserved for an alternative price category for residential ICP's using above 8,000 kWh pa. The pricing would meet the requirements of the Electricity (Low Fixed charge for domestic consumers) regulations in terms of an alternative distribution price.
DM3	NON-PRINCIPAL RESIDENCE	The price category from 1 April 2015 for all residential ICP's which do not meet the criteria of the principal place of residence of a residential consumer in the Electricity (Low Fixed charge for domestic consumers) regulations.
DM4	ALL-INCLUSIVE (Obsolete)	This is an obsolete price category from the former Whangarei City Council Electricity Department. ICP's are being progressively shifted to the DM1 category whenever metering changes are undertaken at these ICP's. It is proposed to eliminate this price category completely from 1 April 2017 by which time the major deployments of advanced meters are scheduled to be complete.
ND1	GENERAL	This is the price category for all general (non-domestic) ICP's up to 100A capacity.
ND2	LARGE COMMERCIAL	ND2 is the price category for ICP's with capacities from 120A to 500A (with CT metering), except for those with half-hour metering.
ND4	SCHOOLS DAY/NIGHT (deleted)	This price category was intended for educational institutions which use night storage heating in winter. With night store heaters progressively being replaced with heat-pumps, this price category was eliminated from 1 April 2015.
ND5	CONTROLLED DAY/NIGHT	ND5 is primarily used by irrigators for pumping overnight. The supply can be interrupted by Northpower to control morning peaks.
ND6	UNMETERED UNCONTROLLED	Roadside equipment cabinets and similar installations which have very low but predictable consumption can utilise this price category.
ND7	UNMETERED PUBLIC LIGHTS	For streetlights and other public amenity lighting.
ND9	DEMAND-BASED PRICING	ND9 (also known as "Code 9") is a demand-based price category for large commercial and industrial sites in the C&I group. Half-hour metering is required. The minimum chargeable demand is 150kVA for each of the Anytime demand and the Network Peak Period demand.
ND10	VOLUME-BASED PRICING	ICP's with half-hour metering that are not suitable for the ND9 category are assigned to the ND10 category which has consumption-based prices.
ND12	BUILDERS TEMPORARY SUPPLY (BTS)	Temporary supplies for construction sites are assigned to ND12. Builders Temporary Supplies are to be utilised solely during the construction phase of permanent structures and are not to be utilised for supplies to dwellings, sheds, caravans, pumps or electric fences. The maximum duration for a Builders Temporary Supply is 12 months.
ND13	LONG TERM DISCONNECTED	ICP's are transferred to the Long Term De-energised Price category when the meters have been removed and the service-line has been completely disconnected at the Network Connection Point but permission has not been obtained to permanently dismantle the supply in accordance with Subpart 3 of Part 4 of the Electricity Industry Act 2010.

IND	VERY LARGE INDUSTRIAL	Sites in the Very Large Industrial consumer group. These sites generally have dedicated supplies directly from a zone substation.
NEWICP	NEW ICP's	The price category assigned to newly created ICP's prior to livening.

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